DOE/EIA-M063(2011)

Documentation of the Oil and Gas Supply Module (OGSM)

July 2011

Office of Energy Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2011*. The major changes include:

- Texas Railroad Commission District 5 is included in the Southwest region instead of the Gulf Coast region.
- Re-estimation of Lower 48 onshore exploration and development costs.
- Updates to crude oil and natural gas resource estimates for emerging shale plays.
- Addition of play-level resource assumptions for tight gas, shale gas, and coalbed methane (Appendix 2.C).
- Updates to the assumptions used for the announced/nonproducing offshore discoveries.
- Revision of the North Slope New Field Wildcat (NFW) exploration wells drilling rate function. The NFW drilling rate is a function of the low-sulfur light projected crude oil prices and was statically estimated based on Alaska Oil and Gas Conservation Commission well counts and success rates.
- Recalibration of the Alaska oil and gas well drilling and completion costs based on the 2007 American Petroleum Institute Joint Association Survey drilling cost data.
- Updates to oil shale plant configuration, cost of capital calculation, and market penetration algorithms.
- Addition of natural gas processing and coal-to-liquids plants as anthropogenic sources of carbon dioxide (CO_2).

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1. Introduction

The purpose of this report is to define the objectives of the Oil and Gas Supply Module (OGSM), to describe the model's basic approach, and to provide detail on how the model works. This report is intended as a reference document for model analysts, users, and the public. It is prepared in accordance with the U.S. Energy Information Administration's (EIA) legal obligation to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Section 57(b)(2)).

Projected production estimates of U.S. crude oil and natural gas are based on supply functions generated endogenously within the National Energy Modeling System (NEMS) by the OGSM. The OGSM encompasses both conventional and unconventional domestic crude oil and natural gas supply. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM projects U.S. domestic oil and gas supply for six Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on forecasted profitability to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

The OGSM utilizes both exogenous input data and data from other modules within the NEMS. The primary exogenous inputs are resource levels, finding-rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the expected returns from projected drilling activities. Regional projections of natural gas wellhead prices and production are provided by the Natural Gas Transmission and Distribution Module (NGTDM). Projections of the crude oil wellhead prices at the OGSM regional level come from the Petroleum Market Model (PMM). Important economic factors, namely interest rates and GDP deflators, flow to the OGSM from the Macroeconomic Module. Controlling information (e.g., forecast year) and expectations information (e.g., expected price paths) come from the Integrating Module (i.e. system module).

Outputs from the OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of the NEMS. To equilibrate supply and demand in the given year, the NGTDM employs short-term supply functions (with the parameters provided by the OGSM) to determine non-associated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. These short-term supply functions reflect potential oil or gas flows to the market for a 1-year period. The gas functions are used by the NGTDM and the oil volumes are used by the PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. The OGSM also provides projections of natural gas production to the PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production is passed to the Integrating Module for reporting purposes. Forecasts of oil and gas production are also provided to the Macroeconomic Module to assist in forecasting aggregate measures of output.

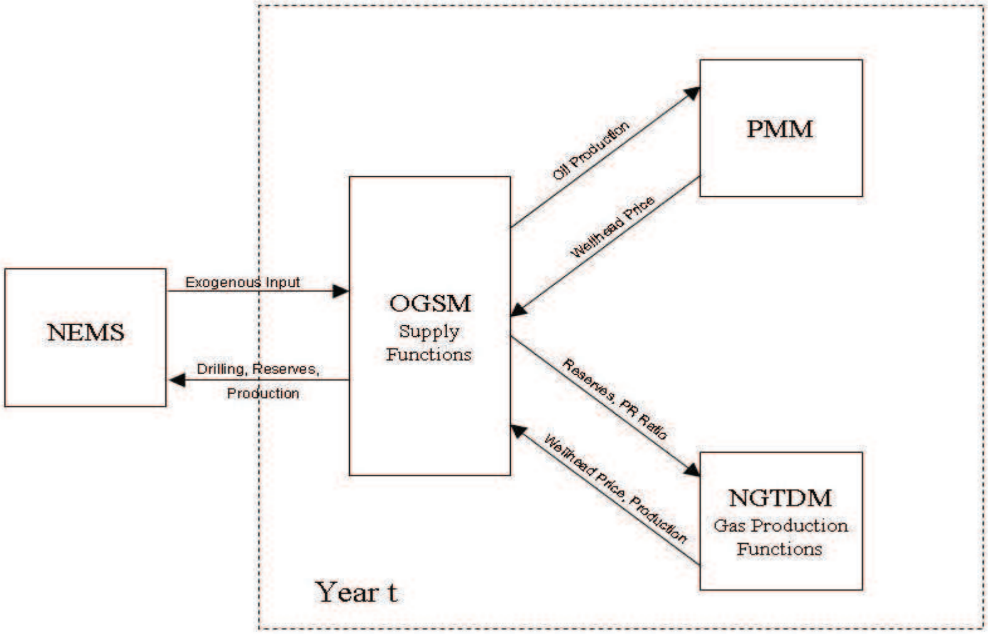
The OGSM is archived as part of the NEMS. The archival package of the NEMS is located under the model acronym NEMS2011. The NEMS version documented is that used to produce the *Annual Energy Outlook 2011 (AEO2011)*. The package is available on the EIA website.[1]

Model Purpose

The OGSM is a comprehensive framework used to analyze oil and gas supply potential and related issues. Its primary function is to produce domestic projections of crude oil and natural gas production as well as natural gas imports and exports in response to price data received endogenously (within the NEMS) from the NGTDM and PMM. Projected natural gas and crude oil wellhead prices are determined within the NGTDM and PMM, respectively. As the supply component only, the OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between the OGSM and the other oil and gas modules is represented in Figure 1-1. The OGSM provides beginning-of-year reserves and the production-to-reserves ratio to the NGTDM for use in its short-term domestic non-associated gas production functions and associated-dissolved natural gas production. The interaction of supply and demand in the NGTDM determines non-associated gas production.

Figure 1-1. OGSM Interface with Other Oil and Gas Modules



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[1] ftp://ftp.eia.doe.gov/pub/forecasts/aeo/

The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding-rate parameters, costs, production profiles, and tax rates -- all of which are critical determinants of the oil and gas supply outlook of the OGSM.

The OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 1-2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply includes lease condensate. Natural gas is differentiated by non-associated and associated-dissolved gas.[2] Non-associated natural gas is categorized by fuel type: low-permeability carbonate and sandstone (conventional), high-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

The OGSM provides mid-term (through year 2035) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables, including:

- drilling and production costs;
- regulatory or legislatively mandated environmental costs;
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits; and
- the rate of penetration for different technologies into the industry by fuel type.

The cash flow approach to the determination of drilling levels enables the OGSM to address some financial issues. In particular, the treatment of financial resources within the OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

The OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification, this feature could allow the model to be used for the analysis of issues involving:

- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and
- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

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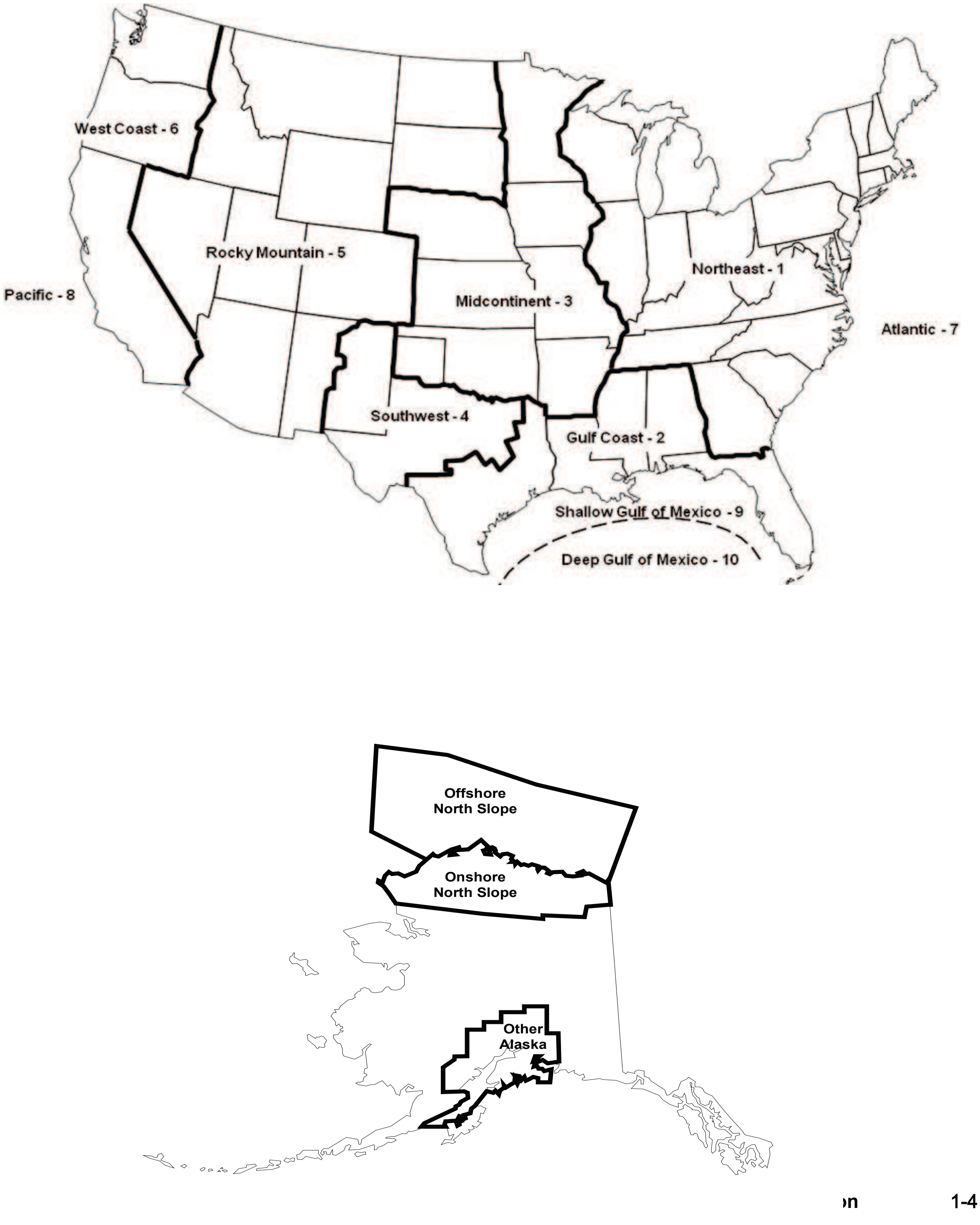
[2] Nonassociated (NA) natural gas is gas not in contact with significant quantities of crude oil in a reservoir. Associated-dissolved natural gas consists of the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

In general, the OGSM is used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

Figure 1-2. Oil and Gas Supply Regions

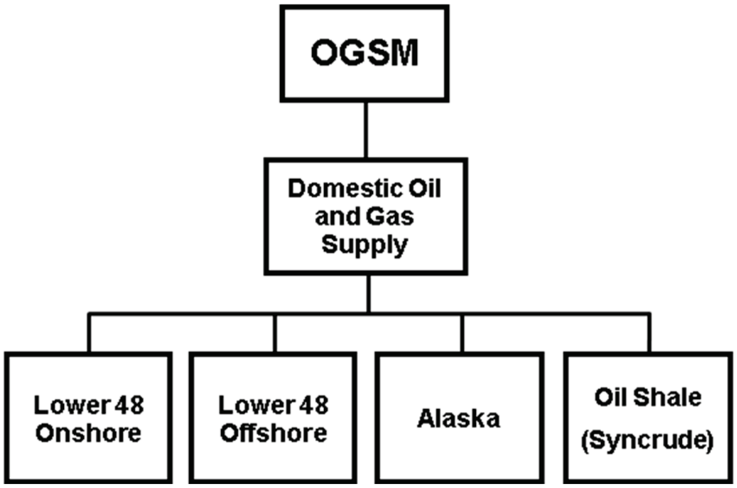


Model Structure

The OGSM consists of a set of submodules (Figure 1-3) and is used to perform supply analysis of domestic oil and gas as part of the NEMS. The OGSM provides crude oil production and parameter estimates representing natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the NEMS. The oil and gas supplies in each period are balanced against the regionally-derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the wellhead and end-use markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and unconventional recovery techniques. Natural gas is categorized by fuel type: high-permeability carbonate and sandstone (conventional), low-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. Liquefied natural gas (LNG) imports and pipeline natural gas import/export trade with Canada and Mexico are determined in the NGTDM.

Figure 1-3. Submodules within the Oil and Gas Supply Module



The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and the NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects. The OGSM incorporates a complete and representative description of the processes by which oil and gas in the technically recoverable resource base[3] convert to proved reserves.[4]

The breadth of supply processes that are encompassed within OGSM result in different methodological approaches for determining crude oil and natural gas production from Lower 48 onshore, Lower 48 offshore, Alaska, and oil shale. The present OGSM consequently comprises four submodules. The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) models crude oil and natural gas supply from resources in the Lower 48 States. The Offshore Oil and Gas Supply Submodule (OOGSS) models oil and gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) models industry supply activity in Alaska. Oil shale (synthetic) is modeled in the Oil Shale Supply Submodule (OSSS). The distinctions of each submodule are explained in individual chapters covering methodology. Following the methodology chapters, four appendices are included: Appendix A provides a description of the discounted cash flow (DCF) calculation; Appendix B is the bibliography; Appendix C contains a model abstract; and Appendix D is an inventory of key output variables.

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[3] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves and inferred reserves as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[4] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

2. Onshore Lower 48 Oil and Gas Supply Submodule

Introduction

U.S. onshore lower 48 crude oil and natural gas supply projections are determined by the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS). The general methodology relies on a detailed economic analysis of potential projects in known crude oil and natural gas fields, enhanced oil recovery projects, developing natural gas plays, and undiscovered crude oil and natural gas resources. The projects that are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. The economic production from the developed projects is aggregated to the regional and the national levels.

OLOGSS utilizes both exogenous input data and data from other modules within the National Energy Modeling System (NEMS). The primary exogenous data includes technical production for each project considered, cost and development constraint data, tax information, and project development data. Regional projections of natural wellhead prices and production are provided by the Natural Gas Transmission and Distribution Model (NGTDM). From the Petroleum Market Module (PMM) come projections of the crude oil wellhead prices at the OGSM regional level.

Model Purpose

OLOGSS is a comprehensive model with which to analyze the crude oil and natural gas supply potential and related economic issues. Its primary purpose is to project production of crude oil and natural gas from the onshore lower 48 in response to price data received from the PMM and the NGTDM. As a supply submodule, OLOGSS does not project prices.

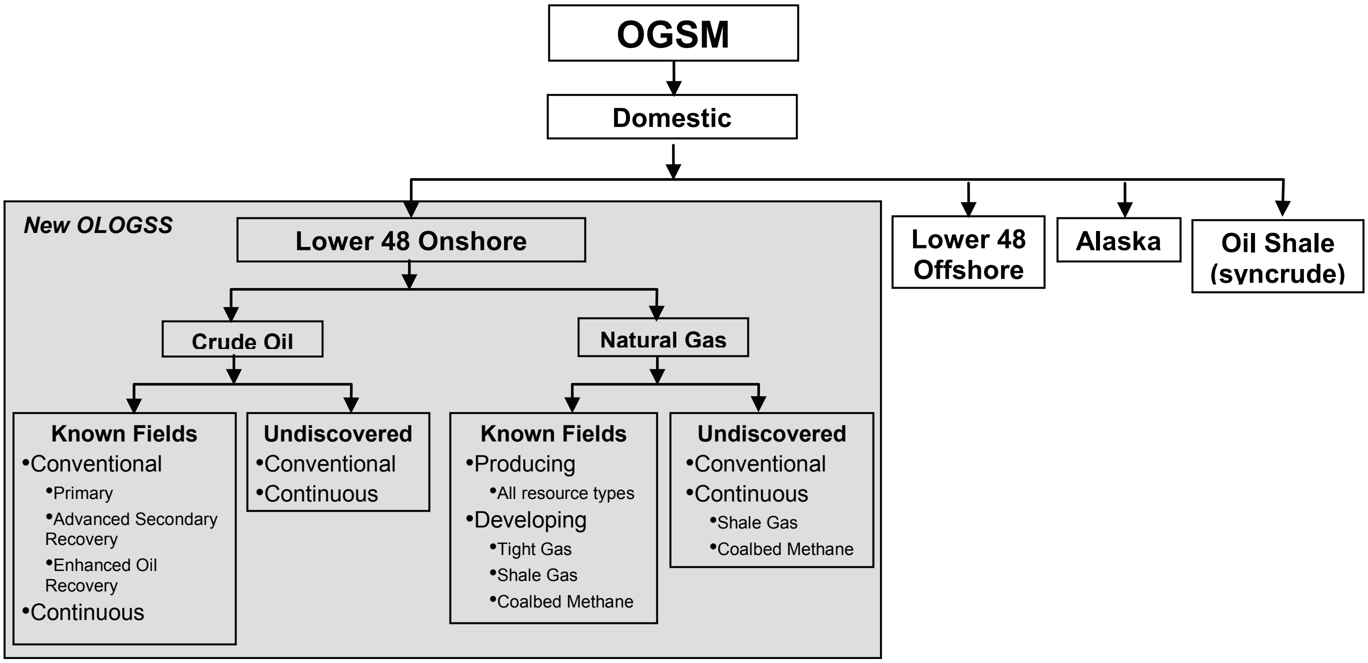
The basic interaction between OLOGSS and the OGSM is illustrated in figure 2-1. As seen in the figure, OLOGSS models the entirety of the domestic crude oil and natural gas production within the onshore lower 48.

Resources Modeled

Crude Oil Resources

Crude oil resources, as illustrated in figure 2-1, are divided into known fields and undiscovered fields. For known resources, exogenous production type curves are used for quantifying the technical production profiles from known fields under primary, secondary, and tertiary recovery processes. Primary resources are also quantified for their advanced secondary recovery (ASR) processes that include the following: waterflooding, infill drilling, horizontal continuity, and horizontal profile modification. Known resources are evaluated for the potential they may possess when employing enhanced oil recovery (EOR) processes such as CO_2 flooding, steam flooding, polymer flooding and profile modification. Known crude oil resources include highly fractured continuous zones such as the Austin chalk formations and the Bakken shale formations.

Figure 2-1: Subcomponents within OGSM



Undiscovered crude oil resources are characterized in a method similar to that used for discovered resources and are evaluated for their potential production from primary and secondary techniques. The potential from an undiscovered resource is defined based on United States Geological Survey (USGS) estimates and is distinguished as either conventional or continuous. Conventional crude oil and natural gas resources are defined as discrete fields with well-defined hydrocarbon-water contacts, where the hydrocarbons are buoyant on a column of water. Conventional resources commonly have relatively high permeability and obvious seals and traps. In contrast, continuous resources commonly are regional in extent, have diffuse boundaries, and are not buoyant on a column of water. Continuous resources have very low permeability, do not have obvious seals and traps, are in close proximity to source rocks, and are abnormally pressured. Included in the category of continuous accumulations are hydrocarbons that occur in tight reservoirs, shale reservoirs, fractured reservoirs, and coal beds.

Natural Gas Resources

Natural gas resources, as illustrated in figure 2-1, are divided into known producing fields, developing natural gas plays, and undiscovered fields. Exogenous production type curves have been used to estimate the technical production from known fields. The undiscovered resources have been characterized based on resource estimates developed by the USGS. Existing databases of developing plays, such as the Marcellus Shale, have been incorporated into the model's resource base. The natural gas resource estimates have been developed from detailed geological characterizations of producing plays.

Processes Modeled

OLOGSS models primary, secondary and tertiary oil recovery processes. For natural gas, OLOGSS models discovered and undiscovered fields, as well as discovered and developing fields. Table 2-1 lists the processes modeled by OLOGSS.

Table 2-1: Processes Modeled by OLOGSS

Crude Oil Processes	Natural Gas Processes
Existing Fields and Reservoirs	Existing Radial Flow
Waterflooding in Undiscovered Resources	Existing Water Drive
CO_2 Flooding	Existing Tight Sands
Steam Flooding	Existing Dry Coal/Shale
Polymer Flooding	Existing Wet Coal/Shale
Infill Drilling	Undiscovered Conventional
Profile Modification	Undiscovered Tight Gas
Horizontal Continuity	Undiscovered Coalbed Methane
Horizontal Profile	Undiscovered Shale Gas
Undiscovered Conventional	Developing Shale Gas
Undiscovered Continuous	Developing Coalbed Methane
	Developing Tight Gas

Major Enhancements

OLOGSS is a play-level model that projects the crude oil and natural gas supply from the onshore lower 48. The modeling procedure includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision. Technological advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The model is able to evaluate the impact of research and development (R&D) on supply and reserves. Furthermore, the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner.

OLOGSS provides a variety of levers that allow the user to model developments affecting the profitability of development:

- Development of new technologies
- Rate of market penetration of new technologies
- Costs to implement new technologies
- Impact of new technologies on capital and operating costs
- Regulatory or legislative environmental mandates

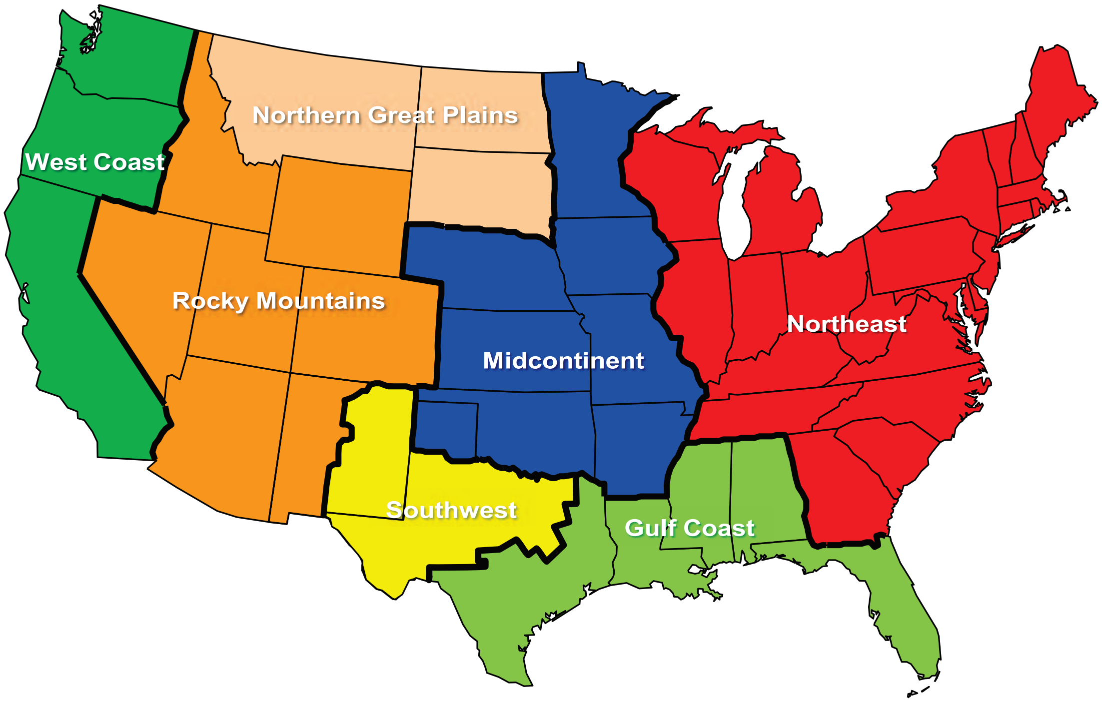
In addition, OLOGSS can quantify the effects of hypothetical developments that affect the resource base. OLOGSS is based on explicit estimates for technically recoverable crude oil and natural gas resources for each source of domestic production (i.e., geographic region/fuel type combinations).

OLOGSS is capable of addressing access issues concerning crude oil and natural gas resources located on federal lands. Undiscovered resources are divided into four categories:

- Officially inaccessible
- Inaccessible due to development constraints
- Accessible with federal lease stipulations
- Accessible under standard lease terms

OLOGSS uses the same geographical regions as the OGSM with one distinction. In order to capture the regional differences in costs and drilling activities in the Rocky Mountain region, the region has been divided into two sub-regions. These regions, along with the original six, are illustrated in figure 2-2. The Rocky Mountain region has been split to add the Northern Great Plains region. The results for these regions are aggregated before being passed to other OGSM or NEMS routines.

Figure 2-2: Seven OLOGSS Regions for Onshore Lower 48



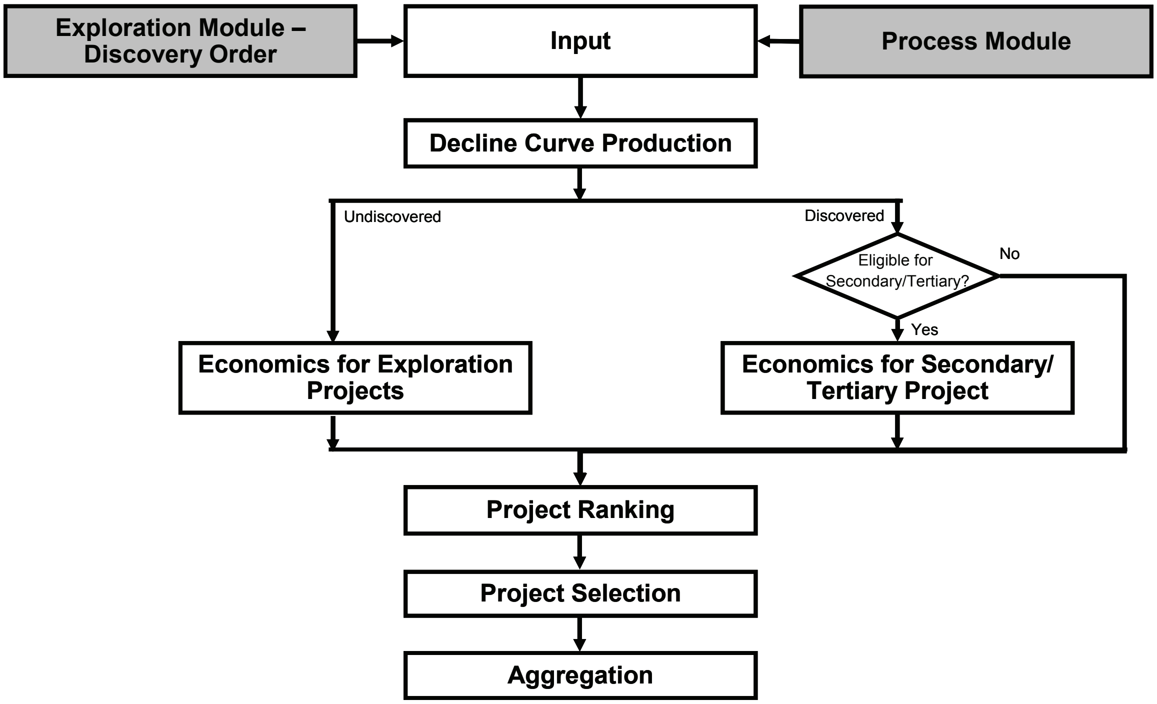
Model Structure

The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development in a way designed to mimic the way decisions are made by the oil and gas industry. Development decisions and project selection depend upon economic viability and the competition for capital, drilling, and other available development constraints. Finally, the model aggregates production and drilling statistics using geographical and resource categories.

Overall System Logic

Figure 2-3 provides the overall system logic for the OLOGSS timing and economic module. This is the only component of OLOGSS which is integrated into NEMS.

Figure 2-3: OLOGSS Timing Module Overall System Logic



As seen in the figure, there are two primary sources of resource data. The exploration module provides the well-level technical production from the undiscovered projects which may be discovered in the next thirty years. It also determines the discovery order in which the projects will be evaluated by OLOGSS. The process module calculates the well-level technical production from known crude oil and natural gas fields, EOR and advanced secondary recovery (ASR) projects, and developing natural gas plays.

OLOGSS determines the potential domestic production in three phases. As seen in Figure 2-3, the first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis. As part of the analysis, each project is subject to a detailed economic analysis used to determine the economic viability and expected life span of the project. In addition, the model applies regional factors used for history matching and resource base coverage. The remaining resources are categorized as either exploration or EOR/ASR. Each year, the exploration projects are subject to economic analysis which determines their economic viability and profitability.

For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based upon the economic life span of the corresponding decline curve project and the process-specific eligibility window. If a project is not currently eligible, it will be re-evaluated in future years. The projects which are eligible are subject to the same type of economic analysis applied to existing and exploration projects in order to determine the viability and relative profitability of the project.

After the economics have been determined for each eligible project, the projects are sorted. The exploration projects maintain their discovery order. The EOR/ASR projects are sorted by their relative profitability. The finalized lists are then considered by the project selection routines.

A project will be selected for development only if it is economically viable and if there are sufficient development resources available to meet the project's requirements. Development resource constraints are used to simulate limits on the availability of infrastructure related to the oil and gas industries. If sufficient resources are not available for an economic project, the project will be reconsidered in future years if it remains economically viable. Other development options are considered in this step, including the waterflooding of undiscovered conventional resources and the extension of CO_2 floods through an increase in total pore volume injected.

The production, reserves, and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

The remainder of this document provides additional details on the logic and particular calculations for each of these steps. These include the decline analysis, economic analysis, timing decisions, project selection, constraints, and modeling of technology.

Known Fields

In this step, the production from existing crude oil and natural gas projects is estimated. A detailed economic analysis is conducted in order to calculate the economically viable production as well as the expected life of each project. The project life is used to determine when a project becomes eligible for EOR and ASR processes.

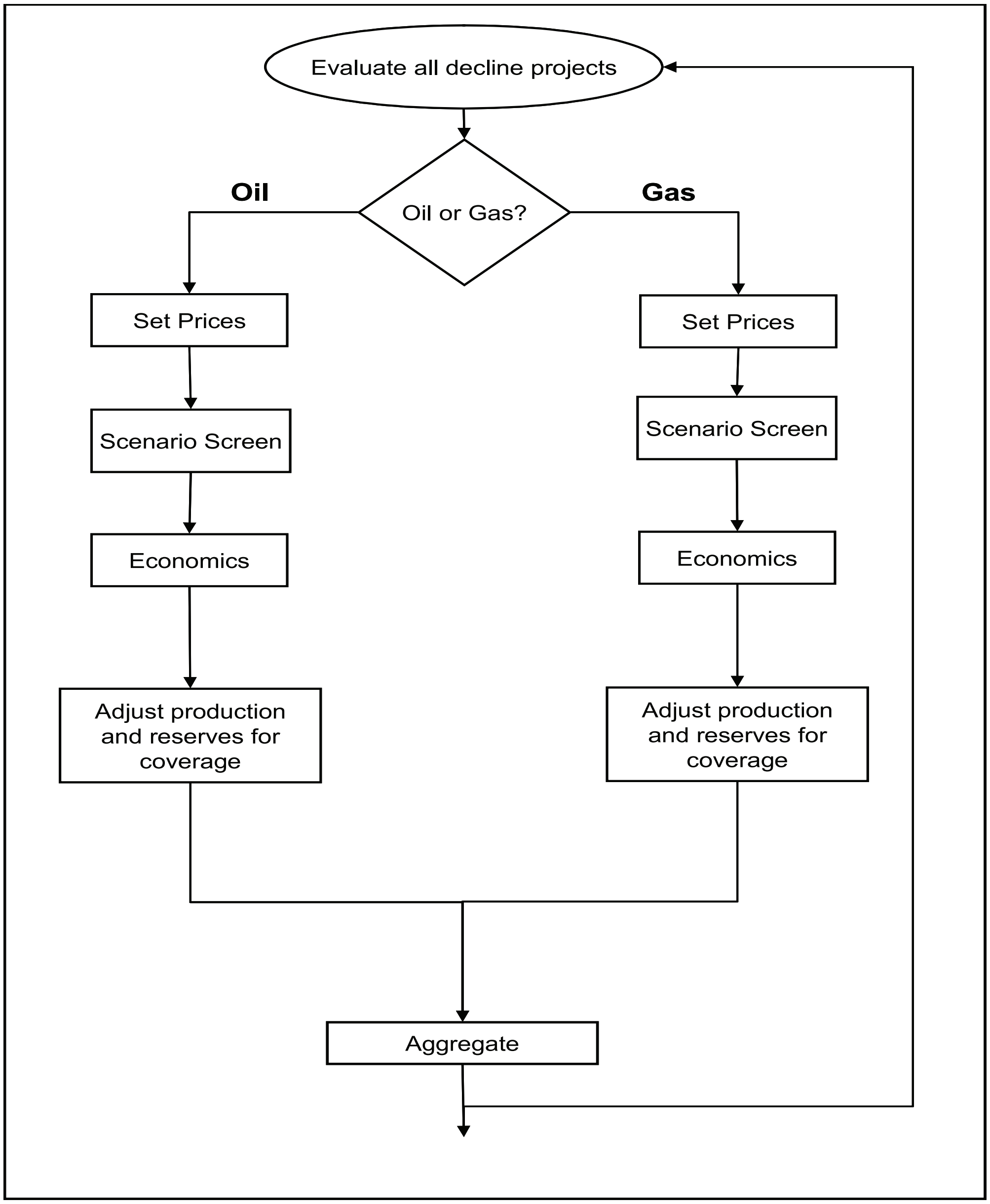
The logic for this process is provided in figure 2-4. For each crude oil project, regional prices are set and the project is screened to determine whether the user has specified any technology and/or economic levers. The screening considers factors including region, process, depth, and several other petro-physical properties. After applicable levers are determined, the project undergoes a detailed economic analysis.

After the analysis, resource coverage factors are applied to the economic production and reserves, and the project results are aggregated at the regional and national levels. In a final step, key parameters including the economic lifespan of the project are stored. A similar process is applied to the existing natural gas fields and reservoirs.

Resource coverage factors are applied in the model to ensure that historical production from existing fields matches that reported by EIA. These factors are calculated at the regional level and applied to production data for the following resources:

- Crude oil (includes lease condensates)
- High-permeability natural gas
- Coalbed methane
- Shale gas
- Tight gas

Figure 2-4: Decline Process Flowchart



Economics

Project Costs

OLOGSS conducts the economic analysis of each project using regional crude oil and natural gas prices. After these prices are set, the model evaluates the base and advanced technology cases for the project. The base case is defined as the current technology and cost scenario for the project; while the advanced case includes technology and/or cost improvements associated with the application of model levers. It is important to note that these cases – for which the assumption are applied to data for the project – are not the same as the *AEO* low, reference, or high technology cases.

For each technology case, the necessary petro-physical properties and other project data are set, the regional dryhole rates are determined, and the process specific depreciation schedule is assigned. The capital and operating costs for the project are then calculated and aggregated for both the base and advanced technology cases.

In the next step, a standard cashflow analysis is conducted, the discounted rate of return is calculated, and the ranking criteria are set for the project. Afterwards, the number and type of wells required for the project, and the last year of actual economic production are set. Finally, the economic variables, including production, development requirements, and other parameters, are stored for project timing and aggregation. All of these steps are illustrated in figure 2-5.

The details of the calculations used in conducting the economic analysis of a project are provided in the following description.

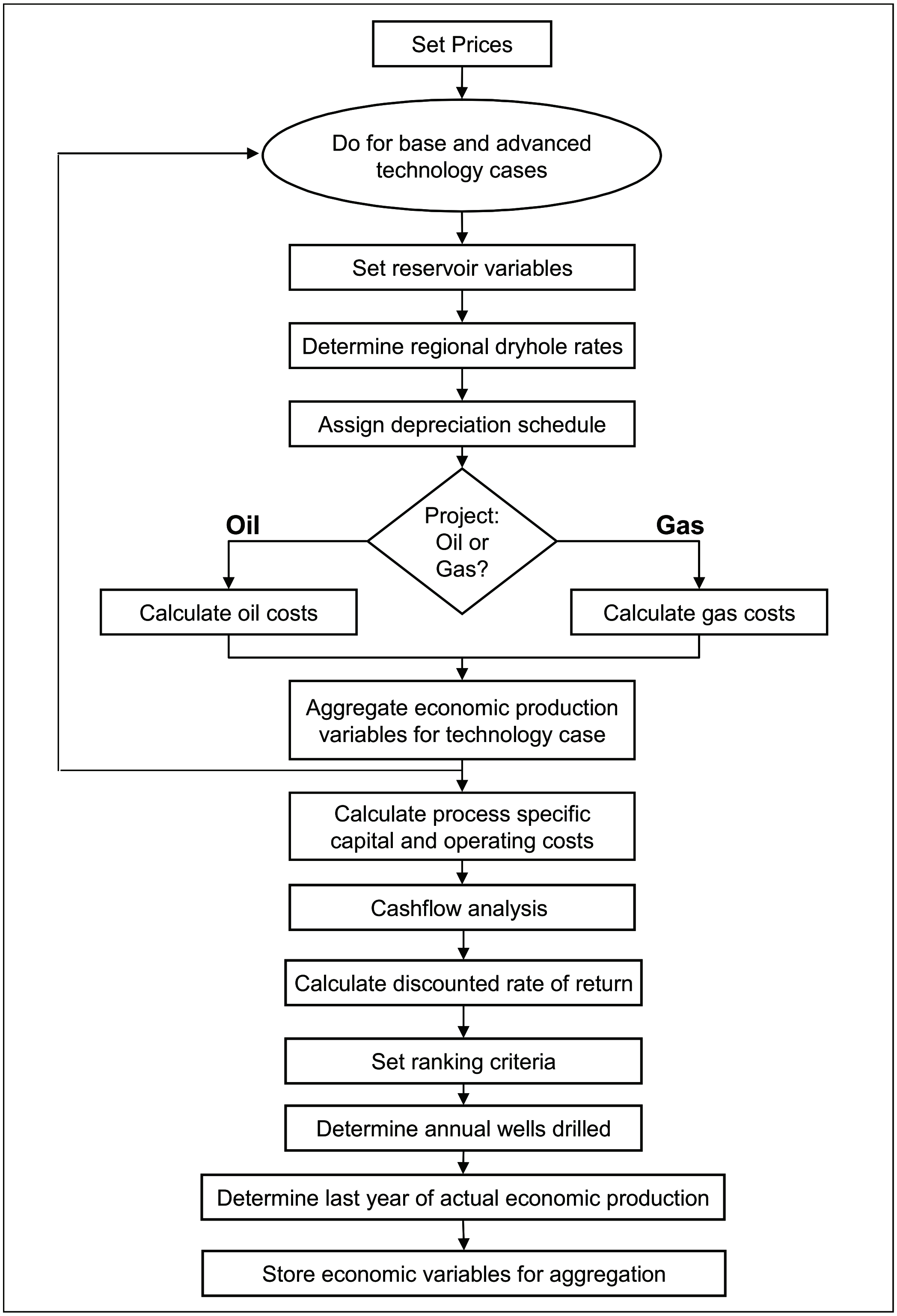
Determine the project shift: The first step is to determine the number of years the project development is shifted, i.e., the numbers of years between the discovery of a project and the start of its development. This will be used to determine the crude oil and natural gas price shift. The number of years is dependent upon both the development schedule – when the project drilling begins – and upon the process.

Determine annual prices: Determine the annual prices used in evaluating the project. Crude oil and natural gas prices in each year use the average price for the previous 5 years.

Begin analysis of base and advanced technology: To capture the impacts of technological improvements on both production and economics, the model divides the project into two categories. The first category – base technology – does not include improvements associated with technology or economic levers. The second category – advanced technology – incorporates the impact of the levers. The division of the project depends on the market penetration algorithm of any applicable technologies.

Determine the dryhole rate for the project: Assigns the regional dryhole rates for undiscovered exploration, undiscovered development, and discovered development. Three types of dryhole rates are used in the model: development in known fields and reservoirs, the first (wildcat) well in an exploration project, and subsequent wells in an exploration project. Specific dryhole rates are used for horizontal drilling and the developing natural gas resources.

Figure 2-5: Economic Analysis Logic



In the advanced case, the dryhole rates may also incorporate technology improvements associated with exploration or drilling success.

$$\mathrm{REGDRYUE}_{\mathrm{im}} = \left(\frac{\mathrm{SUCEXP}_{\mathrm{im}}}{100}\right) * \left(1.0 - \mathrm{DRILL\_FAC}_{\mathrm{itech}}\right) * \mathrm{EXPLR\_FAC}_{\mathrm{itech}} \tag{2-1}$$

$$\mathrm{REGDRYUD}_{\mathrm{im}} = \left(\frac{\mathrm{SUCEXPD}_{\mathrm{im}}}{100}\right) * \left(1.0 - \mathrm{DRILL\_FAC}_{\mathrm{itech}}\right) \tag{2-2}$$

$$\mathrm{REGDRYKD}_{\mathrm{im}} = \left(\frac{\mathrm{SUCDEVE}_{\mathrm{im}}}{100}\right) * \left(1.0 - \mathrm{DRILL\_FAC}_{\mathrm{itech}}\right) \tag{2-3}$$

If evaluating horizontal continuity or horizontal profile, then,

$$\mathrm{REGDRYKD}_{\mathrm{im}} = \left(\frac{\mathrm{SUCCHDEV}_{\mathrm{im}}}{100}\right) * \left(1.0 - \mathrm{DRILL\_FAC}_{\mathrm{itech}}\right) \tag{2-4}$$

If evaluating developing natural gas resources, then,

$$\mathrm{REGDRYUD}_{\mathrm{im}} = \mathrm{ALATNUM}_{\mathrm{ires}} * \left(1.0 - \mathrm{DRILL\_FAC}_{\mathrm{itech}}\right) \tag{2-5}$$

where

ITECH = Technology case number
IM = Region number
REGDRYUE = Project specific dryhole rate for undiscovered exploration (Wildcat)
REGDRYUD = Project specific dryhole rate for undiscovered development
REGDRYKD = Project specific dryhole rate for known field development
SUCEXPD = Regional dryhole rate for undiscovered development

ALATNUM = Variable representing the regional dryhole rate for known field development
SUCDEVE = Regional dryhole rate for undiscovered exploration (Wildcat)
SUCCDEVH = Dryhole rate for horizontal drilling
DRILL_FAC = Technology lever applied to dryhole rate
EXPLR_FAC = Technology factor applied to exploratory dryhole rate

Process specific depreciation schedule: The default depreciation schedule is based on an eight-year declining balance depreciation method. The user may select process-specific depreciation schedules for CO2 flooding, steam flooding, or water flooding in the input file.

Calculate the capital and operating costs for the project: The project costs are calculated for each technology case. The costs are specific to crude oil or natural gas resources. The results of the cost calculations, which include technical crude oil and natural gas production, as well as drilling costs, facilities costs, and operating costs, are then aggregated to the project level.

G & G factor: Calculates the geological and geophysical (G&G) factor for each technology case. This is added to the first year cost.

$$\mathrm{GG}_{\mathrm{itech}} = \mathrm{GG}_{itech} + \mathrm{DRL\_CST}_{itech} * \mathrm{INTANG\_M}_{itech} * \mathrm{GG\_FAC} \tag{2-6}$$

where

$\mathrm{GG}_{\mathrm{itech}}$ = Geophysical and Geological costs for the first year of the project
$\mathrm{DRL\_CST}_{\mathrm{itech}}$ = Total drilling cost for the first year of the project
$\mathrm{INTANG\_M}_{\mathrm{itech}}$ = Energy Elasticity factor for intangible investments (first year)
$\mathrm{GG\_FAC}$ = Portion of exploratory costs that is G&G costs

After the variables are aggregated, the technology case loop ends. At this point, the process specific capital costs, which apply to the entire project instead of the technology case, are calculated.

Cashflow Analysis: The model then conducts a cashflow analysis on the project and calculates the discounted rate of return. Economic Analysis is conducted using a standard cashflow routine described in Appendix A.

Calculate the discounted rate of return: Determines the projected rate of return for all investments and production. The cumulative investments and discounted after tax cashflow are used to calculate the investment efficiency for the project.

Calculate wells: The annual number of new and existing wells is calculated for the project. The model tracks five drilling categories:

- New production wells drilled
- New injection wells drilled
- Active production wells
- Active injection wells
- Shut in wells

The calculation of the annual well count depends on the number of existing production and injection wells as well as on the process and project-specific requirements to complete each drilling pattern developed.

Determine number of years a project is economic: The model calculates the last year of actual economic production. This is based on both the results of the cashflow analysis and the annual production in year specified by the analysis. The last year of production is used to determine the aggregation range to be used if the project is selected for development.

If the project is economic only in the first year, it will be considered uneconomic and unavailable for development at that time. If this occurs for an existing crude oil or natural gas project, the model will assume that all of the wells will be shut in.

Non-producing decline project: Determines if the existing crude oil or natural gas project is non-producing. If there is no production, then the end point for project aggregation is not calculated. This check applies only to the existing crude oil and natural gas projects

Ranking criteria: Ranks investment efficiency based on the discounted after tax cashflow over tangible and intangible investments.

Determine ranking criterion: The ranking criterion, specified by the user, is the parameter by which the projects will be sorted before development. Ranking criteria options include the project net present value, the rate of return for the project, and the investment efficiency.

Calculating Unit Costs

To conduct the cost analysis, the model calculates price adjustment factors as well as unit costs for all required capital and operating costs. Unit costs include the cost of drilling and completing a single well, producing one barrel of crude oil, or operating one well for a year. These costs are adjusted using the technology levers and CPI indices. After the development schedule for the project is determined and the economic life of a single well is calculated, the technical production and injection are determined for the project. Based on the project's development schedule and the technical production, the annual capital and operating costs are determined. In the final step, the process and resource specific capital and operating costs are calculated for the project. These steps are illustrated in figure 2-6.

The Onshore Lower 48 Oil and Gas Supply Submodule uses detailed project costs for economic calculations. There are three broad categories of costs used by the model: capital costs, operating costs, and other costs. These costs are illustrated in figure 2-7. Capital costs encompass the costs of drilling and equipment necessary for the production of crude oil and natural gas resources. Operating costs are used to calculate the full life cycle economics of the project. Operating costs consist of normal daily expenses and surface maintenance. Other cost parameters include royalty, state and federal taxes, and other required schedules and factors.

The calculations for capital costs and operating costs for both crude oil and natural gas are described in detail below. The capital and operating costs are used in the timing and economic module to calculate the lifecycle economics for all crude oil and natural gas projects.

There are two categories for these costs: costs that are applied to all processes, thus defined as *resource independent*, and the process-specific costs, or *resource dependent* costs. Resource dependent costs are used to calculate the economics for existing, reserves growth, and exploration projects. The capital costs for both crude oil and natural gas are calculated first, followed by the resource independent costs, and then the resource dependent costs.

The resource independent and resource dependent costs applied to each of the crude oil and natural gas processes are detailed in tables 2-2 and 2-3 respectively.

Figure 2-6: Project Cost Calculation Procedure

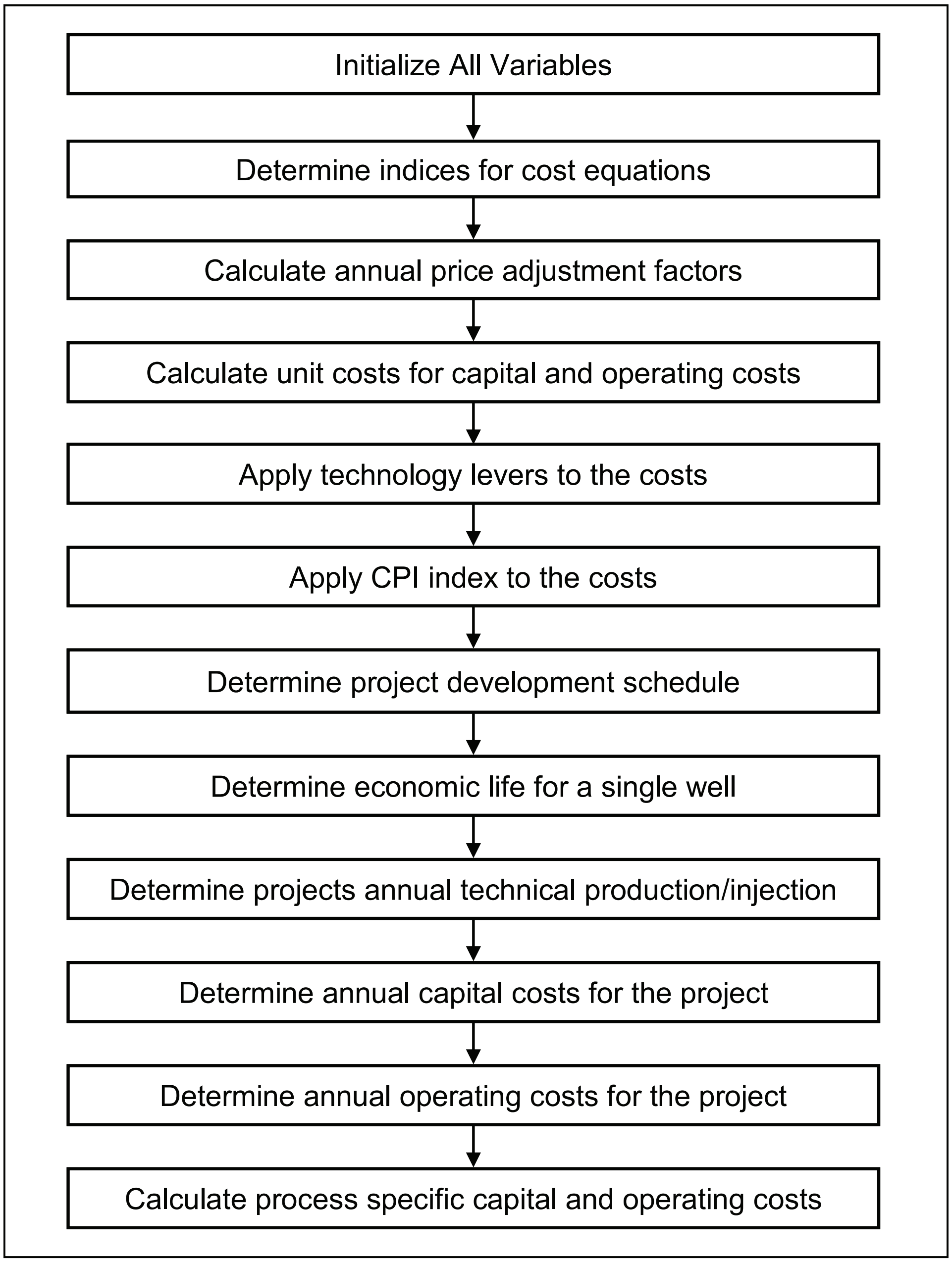


Figure 2-7: Cost Data Types and Requirements

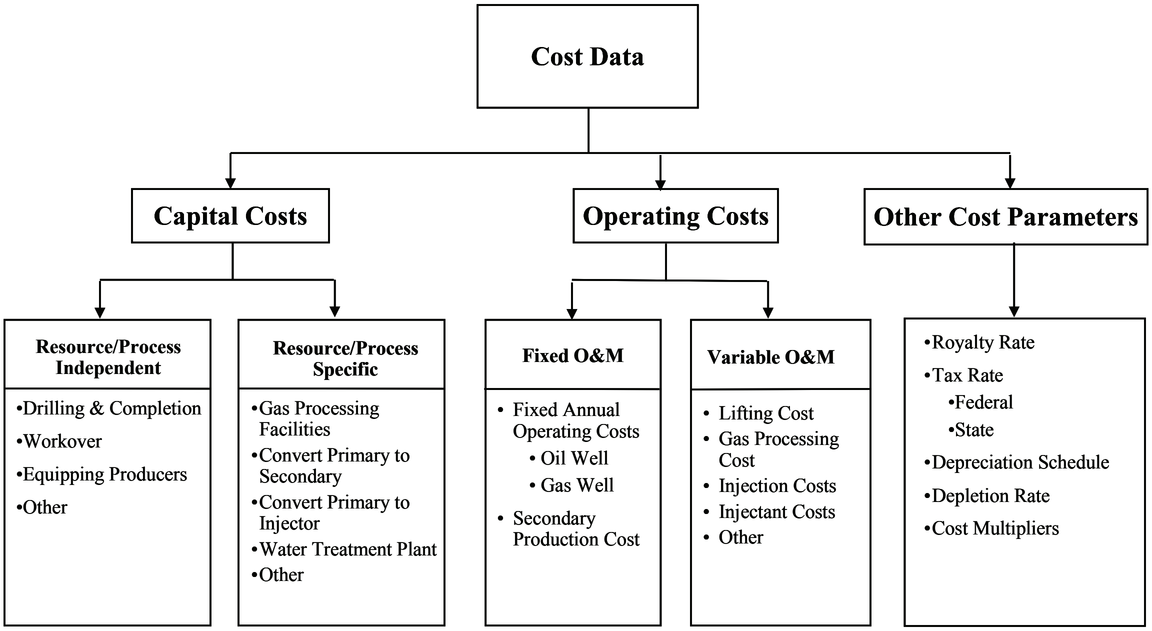


Table 2-2: Costs Applied to Crude Oil Processes

	Capital Cost for Oil	Existing	Water Flooding	CO2 Flooding	Steam Flooding	Polymer Flooding	Infill Drilling	Profile Modification	Undiscovered
Resource Independent	Vertical Drilling Cost	v	v	v	v	V	v	v	v
	Horizontal Drilling Cost								
	Drilling Cost for Dryhole	v	v	v	v	V	v	v	v
	Cost to Equip a Primary Producer		v	v	v	V	v	v	v
	Workover Cost		v	v	v	V	v	v	v
	Facillities Upgrade Cost		v	v	v	V	v	v	
	Fixed Annual Cost for Oil Wells	v	v	v	v	V	v	v	v
	Fixed Annual Cost for Secondary Production		v	v	v	V	v	v	v
	Lifting Cost		v	v	v	V	v	v	v
	O & M Cost for Active Patterns		v			V		v	
	Variable O & M Costs	v	v	v	v	V	v	v	v
	Socondary Workover Cost		v	v	v	V	v	v	v
Resource Dependent	Cost of Water Handling Plant		v			V		v	
	Cost of Chemical Plant					V			
	CO2 Recycle Plant			v					
	Cost of Injectant					V			
	Cost to Convert a Primary to Secondary Well		v	v	v	V	v	v	v
	Cost to Convert a Producer to an Injector		v	v	v	V	v	v	v
	Fixed O & M Cost for Secondary Operations		v	v	v	V	v	v	v
	Cost of a Water Injection Plant		v						
	O & M Cost for Active Patterns per Year		v			V		v	
	Cost to Inject CO2			v					
	King Factor				v				
	Steam Manifolds Cost				v				
	Steam Generators Cost				v				
	Cost to Inject Poloymer					V		v	

Table 2-3: Costs Applied to Natural Gas Processes

	Capital Costs for Gas	Conventional Radial Gas	Water Drive	Tight Sands	Coal/Shale Gas	Undiscovered Conventional
Resource Independent	Vertical Drilling Cost	v	v	v	v	v
	Horizontal Drilling Cost	v	v	v	v	v
	Drilling Cost for Dryhole	v	v	v	v	v
	Gas Facilities Cost	v	v	v	v	v
	Fixed Annual Costs for Gas Wells	v	v	v	v	v
	Gas Stimulation Costs	v	v	v	v	v
	Overhead Costs	v	v	v	v	v
	Variable O & M Cost	v	v	v	v	v
Resource Dependent	Gas Processing and Treatment Facilities	v	v	v	v	v

The following section details the calculations used to calculate the capital and operating costs for each crude oil and natural gas project. The specific coefficients are econometrically estimated according to the corresponding equations in Appendix 2.B.

Cost Multipliers

Cost multipliers are used to capture the impact on capital and operating costs associated with changes in energy prices. OLOGSS calculates cost multipliers for tangible and intangible investments, operating costs, and injectants (polymer and CO_2). The methodology used to calculate the multipliers is based on the National Energy Technology Laboratory (NETL's) Comprehensive Oil and Gas Analysis Model as well as the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.

The multipliers for operating costs and injectant are applied while calculating project costs. The investment multipliers are applied during the cashflow analysis. The injectant multipliers are held constant for the analysis period while the others vary with changing crude oil and natural gas prices.

Operating Costs for Crude Oil: Operating costs are adjusted by the change between current crude oil prices and the base crude oil price. If the crude oil price in a given year falls below a pre-established minimum price, the adjustment factor is calculated using the minimum crude oil price.

$$\text{TERM} = \left(\frac{\text{OILPRICE}_{\text{iyr}} - \text{BASEOIL}}{\text{BASEOIL}} \right) \qquad (2\text{-}7)$$

$$\text{INTANG\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_INT} * \text{TERM}) \qquad (2\text{-}8)$$

$$\text{TANG\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_TANG} * \text{TERM}) \qquad (2\text{-}9)$$

$$\text{OAM\_M}_{\text{iyr}} = 1.0 + (\text{OMULT\_OAM} * \text{TERM}) \qquad (2\text{-}10)$$

where

IYR = Year
TERM = Fractional change in crude oil prices (from base price)
BASEOIL = Base crude oil price used for normalization of capital and operating costs
OMULT_INT = Coefficient for intangible crude oil investment factor
OMULT_TANG = Coefficient for tangible crude oil investment factor
OMULT_OAM = Coefficient for O & M factor
INTANG_M = Annual energy elasticity factor for intangible investments
TANG_M = Annual energy elasticity factor for tangible investments
OAM_M = Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Natural Gas:

$$\mathrm{TERM} = \left(\frac{\mathrm{GASPRICEC}_{iyr} - \mathrm{BASEGAS}}{\mathrm{BASEGAS}} \right) \tag{2-11}$$

$$\mathrm{TANG\_M}_{iyr} = 1.0 + (\mathrm{GMULT\_TANG} * \mathrm{TERM}) \tag{2-12}$$

$$\mathrm{INTANG\_M}_{iyr} = 1.0 + (\mathrm{GMULT\_INT} * \mathrm{TERM}) \tag{2-13}$$

$$\mathrm{OAM\_M}_{iyr} = 1.0 + (\mathrm{GMULT\_OAM} * \mathrm{TERM}) \tag{2-14}$$

where

GASPRICEC = Annual natural gas price
IYR = Year
TERM = Fractional change in natural gas prices
BASEGAS = Base natural gas price used for normalization of capital and operating costs
GMULT_INT = Coefficient for intangible natural gas investment factor
GMULT_TANG = Coefficient for tangible natural gas investment factor
GMULT_OAM = Coefficient for O & M factor
INTANG_M = Annual energy elasticity factor for intangible investments
TANG_M = Annual energy elasticity factor for tangible investments
OAM_M = Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Injectant:

In the first year of the project:

$$\mathrm{FPLY} = 1.0 + (0.3913 * \mathrm{TERM}) \tag{2-15}$$

$$\mathrm{FCO2} = \frac{0.5 + 0.013 * \mathrm{BASEOIL} * (1.0 + \mathrm{TERM})}{0.5 + 0.013 * \mathrm{BASEOIL}} \tag{2-16}$$

where

TERM = Fractional change in crude oil prices
BASEOIL = Base crude oil price used for normalization of capital and operating costs
FPLY = Energy elasticity factor for polymer

FCO2 = Energy elasticity factor for natural CO_2 prices

Resource Independent Capital Costs for Crude Oil

Resource independent capital costs are applied to both crude oil and natural gas projects, regardless of the recovery method applied. The major resource independent capital costs are as follows: drilling and completion costs, the cost to equip a new or primary producer, and workover costs.

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Horizontal Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH^2) + (OIL\_DWCB_{r,d} * DEPTH^2 * NLAT) + (OIL\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}17)$$

Vertical Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH) + (OIL\_DWCB_{r,d} * DEPTH^2) + (OIL\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}18)$$

where

DWC_W = Cost to drill and complete a crude oil well (K$/Well)
r = Region number
d = Depth category number
OIL_DWCA, B, C, K = Coefficients for crude oil well drilling cost equation
DEPTH = Well depth
NLAT = Number of laterals
LATLEN = Length of lateral

Horizontal Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}19)$$

Vertical Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}20)$$

where

DRY_W = Cost to drill a dry well (K$/Well)
R = Region number
D = Depth category number
DRY_DWCA, B, C, K = Coefficients for dry well drilling cost equation
DEPTH = Well depth
NLAT = Number of laterals
LATLEN = Length of lateral

Cost to Equip a New Producer: The cost of equipping a primary producing well includes the production equipment costs for primary recovery.

$$NPR\_W = NPRK_{r,d} + (NPRA_{r,d} * DEPTH) + (NPRB_{r,d} * DEPTH^2) + (NPRC_{r,d} * DEPTH^3) \qquad (2\text{-}21)$$

where

NPR_W = Cost to equip a new producer (K$/Well)
R = Region number
D = Depth category number
NPRA, B, C, K = Coefficients for new producer equipment cost equation
DEPTH = Well depth

Workover Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$WRK\_W = WRKK_{r,d} + (WRKA_{r,d} * DEPTH) + (WRKB_{r,d} * DEPTH^2) + (WRKC_{r,d} * DEPTH^3) \qquad (2\text{-}22)$$

Where,

WRK_W = Cost for a well workover (K$/Well)
R = Region number
D = Depth category number
WRKA, B, C, K = Coefficients for workover cost equation
DEPTH = Well depth

Facilities Upgrade Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities upgrade costs consist of plant costs and electricity costs.

$$FAC\_W = FACUPK_{r,d} + (FACUPA_{r,d} * DEPTH) + (FACUPB_{r,d} * DEPTH^2) + (FACUPC_{r,d} * DEPTH^3) \qquad (2\text{-}23)$$

where

FAC_W = Well facilities upgrade cost (K$/Well)
R = Region number
D = Depth category number
FACUPA, B, C, K = Coefficients for well facilities upgrade cost equation

DEPTH = Well depth

Resource Independent Capital Costs for Natural Gas

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Vertical Drilling Costs:

$$\text{DWC\_W} = \text{GAS\_DWCK}_{r,\,d} + (\text{GAS\_DWCA}_{r,\,d} * \text{DEPTH}) + (\text{GAS\_DWCB}_{r,d} * \text{DEPTH}^2) + (\text{GAS\_DWCC}_{r,\,d} * \text{DEPTH}^3) \tag{2-24}$$

Horizontal Drilling Costs:

$$\text{DWC\_W} = \text{GAS\_DWCK}_{r,\,d} + (\text{GAS\_DWCA}_{r,\,d} * \text{DEPTH}^2) + (\text{GAS\_DWCB}_{r,d} * \text{DEPTH}^2 * \text{NLAT}) + (\text{GAS\_DWCC}_{r,\,d} * \text{DEPTH}^2 * \text{NLAT} * \text{LATLEN}) \tag{2-25}$$

Where,

DWC_W = Cost to drill and complete a natural gas well (K$/Well)
R = Region number
D = Depth category number
GAS_DWCA, B, C, K = Coefficients for natural gas well drilling cost equation
DEPTH = Well depth
NLAT = Number of laterals
LATLEN = Length of lateral

Vertical Drilling Costs for a Dry Well:

$$\text{DRY\_W} = \text{DRY\_DWCK}_{r,\,d} + (\text{DRY\_DWCA}_{r,\,d} * \text{DEPTH}) + (\text{DRY\_DWCB}_{r,d} * \text{DEPTH}^2) + (\text{DRY\_DWCC}_{r,\,d} * \text{DEPTH}^3) \tag{2-26}$$

Horizontal Drilling Costs for a Dry Well:

$$\text{DRY\_W} = \text{DRY\_DWCK}_{r,\,d} + (\text{DRY\_DWCA}_{r,\,d} * \text{DEPTH}^2) + (\text{DRY\_DWCB}_{r,d} * \text{DEPTH}^2 * \text{NLAT}) + (\text{DRY\_DWCC}_{r,\,d} * \text{DEPTH}^2 * \text{NLAT} * \text{LATLEN}) \tag{2-27}$$

where

DRY_W = Cost to drill a dry well (K$/Well)
R = Region number
D = Depth category number
DRY_DWCA, B, C, K = Coefficients for dry well drilling cost equation
DEPTH = Well depth
NLAT = Number of laterals
LATLEN = Length of lateral

Facilities Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities costs consist of flowlines and connections, production package costs, and storage tank costs.

$$\begin{aligned} FWC\_W_{iyr} = {} & FACGK_{r,\,d} + (FACGA_{r,\,d} * DEPTH) + (FACGB_{r,\,d} * PEAKDAILY\_RATE) \\ & + (FACGC_{r,\,d} * DEPTH * PEAKDAILY\_RATE) \end{aligned} \tag{2-28}$$

where

FWC_W = Facilities cost for a natural gas well (K$/Well)
R = Region number
D = Depth category number
FACGA, B, C, K = Coefficients for facilities cost equation
DEPTH = Well depth
PEAKDAILY_RATE = Maximum daily natural gas production rate

Fixed Annual Operating Costs: The fixed annual operating costs are applied to natural gas projects in decline curve analysis.

$$\begin{aligned} FOAMG\_W = {} & OMGK_{r,\,d} + (OMGA_{r,\,d} * DEPTH) + (OMGB_{r,\,d} * PEAKDAILY\_RATE) \\ & + (OMGC_{r,\,d} * DEPTH * PEAKDAILY\_RATE) \end{aligned} \tag{2-29}$$

where

FOAMG_W = Fixed annual operating costs for natural gas (K$/Well)
R = Region number
D = Depth category number
OMGA, B, C, K = Coefficients for fixed annual O & M cost equation for natural gas
DEPTH = Well depth
PEAKDAILY_RATE = Maximum daily natural gas production rate

Resource Independent Annual Operating Costs for Crude Oil

Fixed Operating Costs: The fixed annual operating costs are applied to crude oil projects in decline curve analysis.

$$\begin{aligned} OMO\_W = {} & OMOK_{r,\,d} + (OMOA_{r,\,d} * DEPTH) + (OMOB_{r,\,d} * DEPTH^2) \\ & + (OMOC_{r,\,d} * DEPTH^3) \end{aligned} \tag{2-30}$$

where

OMO_W = Fixed annual operating costs for crude oil wells (K$/Well)
R = Region number
D = Depth category number
OMOA, B, C, K = Coefficients for fixed annual operating cost equation for crude oil
DEPTH = Well depth

Annual Costs for Secondary Producers: The direct annual operating expenses include costs in the following major areas: normal daily expenses, surface maintenance, and subsurface maintenance.

$$OPSEC\_W = OPSECK_{r,d} + (OPSECA_{r,d} * DEPTH) + (OPSECB_{r,d} * DEPTH^2) + (OPSECC_{r,d} * DEPTH^3) \quad (2\text{-}31)$$

where

OPSEC_W = Fixed annual operating cost for secondary oil operations (K$/Well)
R = Region number
D = Depth category number
OPSECA, B, C, K = Coefficients for fixed annual operating cost for secondary oil operations
DEPTH = Well depth

Lifting Costs: Incremental costs are added to a primary and secondary flowing well. These costs include pump operating costs, remedial services, workover rig services and associated labor.

$$OML\_W = OMLK_{r,d} + (OMLA_{r,d} * DEPTH) + (OMLB_{r,d} * DEPTH^2) + (OMLC_{r,d} * DEPTH^3) \quad (2\text{-}32)$$

where

OML_W = Variable annual operating cost for lifting (K$/Well)
R = Region number
D = Depth category number
OMLA, B, C, K = Coefficients for variable annual operating cost for lifting equation
DEPTH = Well depth

Secondary Workover: Secondary workover, also known as stimulation is done every 2-3 years to increase the productivity of a secondary producing well. In some cases secondary workover or stimulation of a wellbore is required to maintain production rates.

$$SWK\_W = OMSWRK_{r,d} + (OMSWR\ A_{r,d} * DEPTH) + (OMSWR\ B_{r,d} * DEPTH^2) + (OMSWR\ C_{r,d} * DEPTH^3) \quad (2\text{-}33)$$

where

SWK_W = Secondary workover costs (K$/Well)
R = Region number
D = Depth category number
OMSWRA, B, C, K = Coefficients for secondary workover costs equation
DEPTH = Well depth

Stimulation Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$\mathrm{STIM\_W} = \left(\frac{\mathrm{STIM\_A} + \mathrm{STIM\_B} * \mathrm{DEPTH}}{1000} \right) \tag{2-34}$$

where

STIM_W = Oil stimulation costs (K$/Well)
STIM_A, B = Stimulation cost equation coefficients
DEPTH = Well depth

Resource Dependent Capital Costs for Crude Oil

Cost to Convert a Primary Well to a Secondary Well: These costs consist of additional costs to equip a primary producing well for secondary recovery. The cost of replacing the old producing well equipment includes costs for drilling and equipping water supply wells but excludes tubing costs.

$$\begin{aligned} \mathrm{PSW\_W} = {} & \mathrm{PSWK}_{r,d} + (\mathrm{PSWA}_{r,d} * \mathrm{DEPTH}) + (\mathrm{PSWB}_{r,d} * \mathrm{DEPTH}^2) \\ & + (\mathrm{PSWC}_{r,d} * \mathrm{DEPTH}^3) \end{aligned} \tag{2-35}$$

where

PSW_W = Cost to convert a primary well into a secondary well (K$/Well)
R = Region number
D = Depth category number
PSWA, B, C, K = Coefficients for primary to secondary well conversion cost equation
DEPTH = Well depth

Cost to Convert a Producer to an Injector: Producing wells may be converted to injection service because of pattern selection and favorable cost comparison against drilling a new well. The conversion procedure consists of removing surface and sub-surface equipment (including tubing), acidizing and cleaning out the wellbore, and installing new 2- 7/8 inch plastic-coated tubing and a waterflood packer (plastic-coated internally and externally).

$$\begin{aligned} \mathrm{PSI\_W} = {} & \mathrm{PSIK}_{r,d} + (\mathrm{PSIA}_{r,d} * \mathrm{DEPTH}) + (\mathrm{PSIB}_{r,d} * \mathrm{DEPTH}^2) \\ & + (\mathrm{PSIC}_{r,d} * \mathrm{DEPTH}^3) \end{aligned} \tag{2-36}$$

where

PSI_W = Cost to convert a producing well into an injecting well (K$/Well)
R = Region number
D = Depth category number
PSIA, B, C, K = Coefficients for producing to injecting well conversion cost equation
DEPTH = Well depth

Cost of Produced Water Handling Plant: The capacity of the water treatment plant is a function of the maximum daily rate of water injected and produced (MBbl) throughout the life of the project.

$$\mathrm{PWP\_F} = \mathrm{PWHP} * \left(\frac{\mathrm{RMAXW}}{365}\right) \tag{2-37}$$

where

PWP_F = Cost of the produced water handling plant (K$/Well)
PWHP = Produced water handling plant multiplier
RMAXW = Maximum pattern level annual water injection rate

Cost of Chemical Handling Plant (Non-Polymer): The capacity of the chemical handling plant is a function of the maximum daily rate of chemicals injected throughout the life of the project.

$$\mathrm{CHM\_F} = \mathrm{CHMK} * \mathrm{CHMA} * \left(\frac{\mathrm{RMAXP}}{365}\right)^{\mathrm{CHMB}} \tag{2-38}$$

where

CHM_F = Cost of chemical handling plant (K$/Well)
CHMB = Coefficient for chemical handling plant cost equation
CHMK, A = Coefficients for chemical handling plant cost equation
RMAXP = Maximum pattern level annual polymer injection rate

Cost of Polymer Handling Plant: The capacity of the polymer handling plant is a function of the maximum daily rate of polymer injected throughout the life of the project.

$$\mathrm{PLY\_F} = \mathrm{PLYPK} * \mathrm{PLYPA} * \left(\frac{\mathrm{RMAXP}}{365}\right)^{0.6} \tag{2-39}$$

where

PLY_F = Cost of polymer handling plant (K$/Well)
PLYPK, A = Coefficients for polymer handling plant cost equation
RMAXP = Maximum pattern level annual polymer injection rate

Cost of CO_2 Recycling Plant: The capacity of a recycling/injection plant is a function of the maximum daily injection rate of CO_2 (Mcf) throughout the project life. If the maximum CO_2 rate equals or exceeds 60 MBbl/Day then the costs are divided into two separate plant costs.

$$\mathrm{CO2\_F} = \mathrm{CO2rk} * \left(\frac{0.75 * \mathrm{RMAXP}}{365}\right)^{\mathrm{CO2RB}} \tag{2-40}$$

where,

CO2_F = Cost of CO_2 recycling plant (K$/Well)
CO2RK, CO2RB = Coefficients for CO_2 recycling plant cost equation
RMAXP = Maximum pattern level annual CO_2 injection rate

Cost of Steam Manifolds and Pipelines: Cost to install and maintain steam manifolds and pipelines for steam flood enhanced oil recovery project.

$$\text{STMM\_F} = \text{TOTPAT} * \text{PATSZE} * \text{STMMA} \tag{2-41}$$

where

STMM_F = Cost for steam manifolds and generation (K$)
TOTPAT = Total number of patterns in the project
PATSZE = Pattern size (Acres)
STMMA = Steam manifold and pipeline cost (per acre)

Resource Dependant Annual Operating Costs for Crude Oil

Injection Costs: Incremental costs are added for secondary injection wells. These costs include pump operating, remedial services, workover rig services, and associated labor.

$$\begin{aligned}\text{OPINJ\_W} = {} & \text{OPINJK}_{r,\,d} + (\text{OPINJA}_{r,\,d} * \text{DEPTH}) + (\text{OPINJ B}_{r,\,d} * \text{DEPTH}^2) \\ & + (\text{OPINJ C}_{r,\,d} * \text{DEPTH}^3)\end{aligned} \tag{2-42}$$

where

OPINJ_W = Variable annual operating cost for injection (K$/Well)
R = Region number
D = Depth category number
OPINJA, B, C, K = Coefficients for variable annual operating cost for injection equation
DEPTH = Well depth

Injectant Cost: The injectant costs are added for the secondary injection wells. These costs are specific to the recovery method selected for the project. Three injectants are modeled: polymer, CO_2 from natural sources, and CO_2 from industrial sources.

Polymer Cost:

$$\text{POLYCOST} = \text{POLYCOST} * \text{FPLY} \tag{2-43}$$

where

POLYCOST = Cost of polymer ($/Lb)
FPLY = Energy elasticity factor for polymer

Natural CO_2 Cost: Cost to drill, produce and ship CO_2 from natural sources, namely CO_2 fields in Western Texas.

$$\text{CO2COST} = \text{CO2K} + (\text{CO2B} * \text{OILPRICEO(1)}) \tag{2-44}$$

$$\text{CO2COST} = \text{CO2COST} * \text{CO2PR(IST)} \tag{2-45}$$

where

CO2COST = Cost of natural CO_2 ($/Mcf)
IST = State identifier
CO2K, CO2B = Coefficients for natural CO_2 cost equation
OILPRICEO(1) = Crude oil price for first year of project analysis
CO2PR = State CO_2 cost multiplier used to represent changes in cost associated with transportation outside of the Permian Basin

Industrial CO_2 Cost: Cost to capture and transport CO_2 from industrial sources. These costs include the capture, compression to pipeline pressure, and the transportation to the project site via pipeline. The regional costs, which are specific to the industrial source of CO_2, are exogenously determined and provided in the input file.

Industrial CO_2 sources include

- Hydrogen Plants
- Ammonia Plants
- Ethanol Plants
- Cement Plants
- Hydrogen Refineries
- Power Plants
- Natural Gas Processing Plants
- Coal to Liquids

After unit costs have been calculated for the project, they are adjusted using technology levers as well as CPI multipliers. Two types of levers are applied to the costs. The first is the fractional change in cost associated with a new technology. The second is the incremental cost associated with implementing the new technology. These factors are determined by the model user. As an example,

$$NPR\_W = (NPR\_W * CHG\_FAC\_FAC(ITECH)) + CST\_FAC\_FAC(ITECH) \qquad (2\text{-}46)$$

where,

NPR_W = Cost to equip a new oil producer (K$/well)
CHG_FAC_FAC = Fractional change in cost associated with technology improvements
CST_FAC_FAC = Incremental cost to apply the new technology
ITECH = Technology case (Base or Advanced)

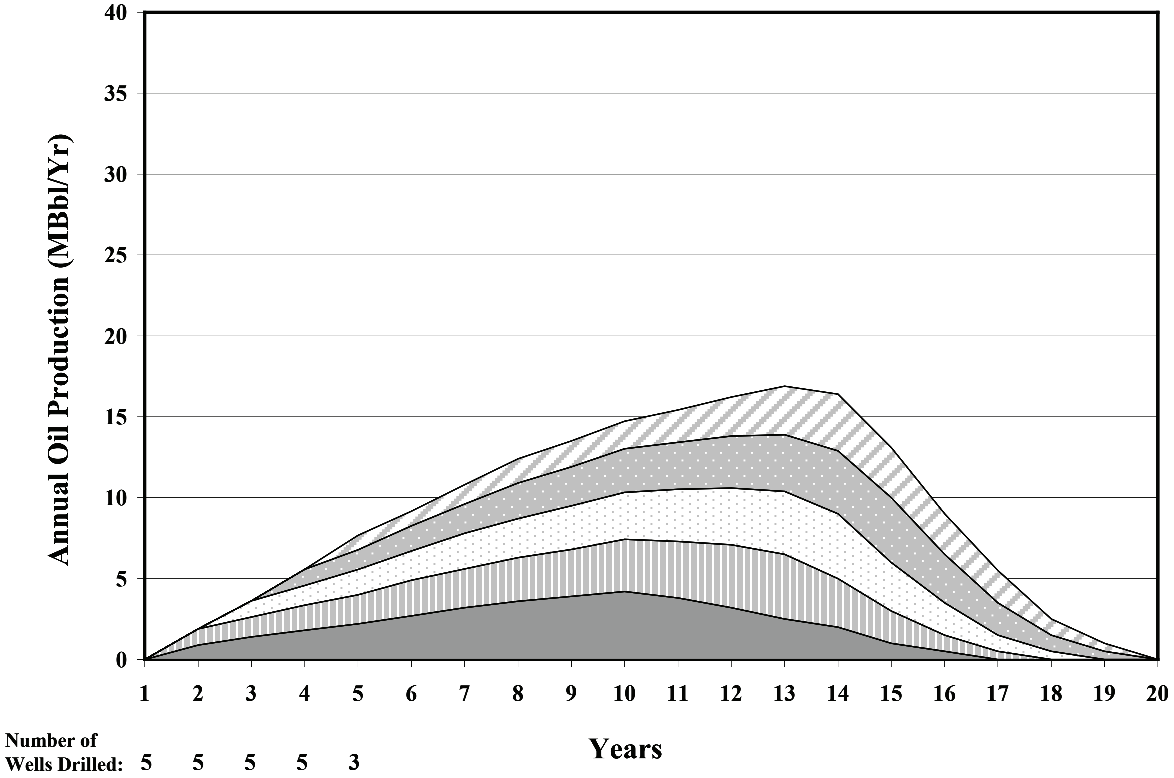
Determining Technical Production

The development schedule algorithms determine how the project's development over time will be modeled. They calculate the number of patterns initiated per year and the economic life of the well. The economic life is the number of years in which the revenue from production exceeds the costs required to produce the crude oil and natural gas.

The model then aggregates the well-level production of crude oil, natural gas, water, and injectant based upon the pattern life and number of wells initiated each year. The resulting profile is the technical production for the project.

Figure 2-8 shows the crude oil production for one project over the course of its life. The graph shows a hypothetical project. In this scenario patterns are initiated for five years. Each shaded area is the annual technical production associated with the initiated patterns.

Figure 2-8: Calculating Project Level Technical Production



The first step in modeling the technical production is to calculate the number of patterns drilled each year. The model uses several factors in calculating the development schedule:

- Potential delays between the discovery of the project and actual initiation
- The process modeled
- The resource access – the number of patterns developed each year is reduced if the resource is subject to cumulative surface use limitations
- The total number of patterns in the project
- The crude oil and natural gas prices
- The user specified maximum and minimum number of patterns developed each year
- The user specified percentage of the project to be developed each year
- The percentage of the project which is using base or advanced technology.

These apply to the EOR/ASR projects as well as the undiscovered and currently developing ones. The projects in existing fields and reservoirs are assumed to have all of their patterns – the number of active wells – developed in the first year of the project.

After calculating the number of patterns initiated each year, the model calculates the number of patterns which are active for each year of the project life.

Production Profile of the Project: For all EOR/ASR, undiscovered, and developing processes, the project level technical production is calculated using well-level production profiles. For infill projects, the production is doubled because the model assumes that there are two producers in each pattern.

$$\mathrm{OILPROD}_{iyr1} = \mathrm{OILPROD}_{iyr1} + (\mathrm{OPROD}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-47}$$
$$\mathrm{GASPROD}_{iyr1} = \mathrm{OILPROD}_{iyr1} + (\mathrm{GPROD}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-48}$$
$$\mathrm{NGLPROD}_{iyr1} = \mathrm{NGLPROD}_{iyr1} + (\mathrm{NPROD}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-49}$$
$$\mathrm{WATPROD}_{iyr1} = \mathrm{WATPROD}_{iyr1} + (\mathrm{WPROD}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-50}$$
$$\mathrm{TOTINJ}_{iyr1} = \mathrm{TOTINJ}_{iyr1} + (\mathrm{OINJ}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-51}$$
$$\mathrm{WATINJ}_{iyr1} = \mathrm{WATINJ}_{iyr1} + (\mathrm{WINJ}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-52}$$
$$\mathrm{TORECY}_{iyr1} = \mathrm{TORECY}_{iyr1} + (\mathrm{ORECY}_{kyr} * \mathrm{PATN}_{iyr}) \tag{2-53}$$
$$\mathrm{SUMP}_{iyr1} = \mathrm{SUMP}_{iyr1} + \mathrm{PATN}_{iyr} \tag{2-54}$$

where

IYR1 = Number of years
IYR = Year of project development
JYR = Number of years the project is developed
KYR = Year (well level profile)
LYR = Last project year in which pattern level profile is applied
OPROD = Pattern level annual crude oil production
GPROD = Pattern level annual natural gas production
NPROD = Pattern level annual NGLl production
WPROD = Pattern level annual water production
WINJ = Pattern level annual water injection
OINJ = Pattern level annual injectant injection
ORECY = Pattern level annual injectant recycled
PATN = Number of patterns initiated each year
SUMP = Cumulative number of patterns developed
OILPROD = Project level annual crude oil production
GASPROD = Project level annual natural gas production
NGLPROD = Project level annual NGL production
WATPROD = Project level annual water production
WATINJ = Project level annual water injection
TOTINJ = Project level annual injectant injection
TORECY = Project level annual injectant recycled

Reviewer's note: The equations above are confusing, because the same variable appears on the LHS and RHS. I'm guessing that the variable is simply being incremented on an annual basis, i.e., that the first equation should read something like

In any case, please clarify what is happening in the equations and use a new variable name on the LHS.

Resource Accounting

OLOGSS incorporates a complete and representative description of the processes by which crude oil and natural gas in the technically recoverable resource base[1] are converted to proved reserves.[2]

OLOGSS distinguishes between drilling for new fields (new field wildcats) and drilling for additional deposits within old fields (other exploratory and developmental wells). This enhancement recognizes important differences in exploratory drilling, both by its nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions.

End of Year Reserves: The model calculates two types of end of year (EOY) reserves at the project level: inferred reserves and proved reserves. Inferred reserves are calculated as the total technical production minus the technical production from patterns initiated through a particular year. Proved reserves are calculated as the technical production from wells initiated through a particular year minus the cumulative production from those patterns.

Inferred reserves = total technical production – technical production for wells initiated

$$\mathrm{airsvoil(ires,n)} = \sum_{\text{`}i=1}^{\mathrm{max\_yr}}\left[\sum_{j=1}^{\mathrm{ilife}}(\mathrm{oprod}(j))\times\mathrm{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{\mathrm{ilife}}(\mathrm{oprod}(j))\times\mathrm{patn}(i)\right] \tag{2-55}$$

$$\mathrm{airsvgas(ires,n)} = \sum_{\text{`}i=1}^{\mathrm{max\_yr}}\left[\sum_{j=1}^{\mathrm{ilife}}(\mathrm{gprod}(j))\times\mathrm{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{\mathrm{ilife}}(\mathrm{gprod}(j))\times\mathrm{patn}(i)\right] \tag{2-56}$$

Reviewers note: It's not clear what "ires" is above. Also, it looks like all of these equations can be simplified by writing the outer sums from n+1 to max_yr, e.g.,

Proved reserves = technical production for patterns initiated – cumulative production

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[1] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[2] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3] *Undiscovered resources* are located outside of oil and gas fields, in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[4] *Inferred reserves* are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

$$\mathrm{aresvoil(ires,n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}(\mathrm{oprod}(j)) \times \mathrm{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{n}(\mathrm{oprod}(j)) \times \mathrm{patn}(i)\right] \tag{2-57}$$

$$\mathrm{aresvgas(ires,n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}(\mathrm{gprod}(j)) \times \mathrm{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{n}(\mathrm{gprod}(j)) \times \mathrm{patn}(i)\right] \tag{2-58}$$

where,

I, J = Years
N = Current year evaluated
ILIFE = Pattern life
MAX_YR = Maximum number of years
OPROD = Pattern level annual crude oil production
GPROD = Pattern level annual natural gas production
PATN = Number of patterns developed each year
AIRSVOIL = Annual inferred crude oil reserves
AIRSVGAS = Annual inferred natural gas reserves
ARESVOIL = Annual proved oil reserves
ARESVGAS = Annual proved natural gas reserves

For existing crude oil and natural gas projects, the model calculates the proved reserves. For these processes, the proved reserves are defined as the total technical production divided by the life of the project.

Calculating Project Costs

The model uses four drilling categories for the calculation of drilling and facilities costs. These categories are:

- New producers
- New injectors
- Conversions of producers to injectors
- Conversions of primary wells to secondary wells.

The number of ??? in each category required for the pattern is dependent upon the process and the project.

Project Level Process Independent Costs

Drilling costs and facility costs are determined at the project level.

Drilling Costs: Drilling costs are calculated using one of four approaches, depending on the resource and recovery process. These approaches apply to the following resources:

- Undiscovered crude oil and natural gas
- Existing crude oil and natural gas fields
- EOR/ASR projects
- Developing natural gas projects

<u>For undiscovered crude oil and natural gas resources:</u> The first well drilled in the first year of the project is assumed to be a wildcat well. The remaining wells are assumed to be undiscovered development wells. This is reflected in the application of the dryhole rates.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUE_{R}) * 1.0 * XPP1 \quad (2\text{-}59)$$

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_{R}) * (PATN_{iyr} - 1 * XPP1) \quad (2\text{-}60)$$

For existing crude oil and natural gas fields: As the field is already established, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_{R}) * (PATDEV_{ires,iyr, itech} * XPP1) \quad (2\text{-}61)$$

For EOR/ASR Projects: As the project is in an established and known field, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_{R}) * (PATN_{iyr} * XPP1) \quad (2\text{-}62)$$

For developing natural gas projects: As the project is currently being developed, it is assumed that the wildcat well(s) have previously been drilled. Therefore, the undiscovered developmental dryhole rate is applied to the project.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_{R}) * (PATN_{iyr} * XPP1) \quad (2\text{-}63)$$

where

IRES = Project index number
IYR = Year
R = Region
PATDEV = Number of patterns initiated each year for base and advanced technology cases
PATN = Annual number of patterns initiated
DRL_CST2 = Technology case specific annual drilling cost
DWC_W = Cost to drill and complete a well
DRY_W = Cost to drill a dryhole
REGDRYUE = Dryhole rate for undiscovered exploration (wildcat)
REGDRYUD = Dryhole rate for undiscovered development
REGDRYKD = Dryhole rate for known fields development
XPP1 = Number of producing wells drilled per pattern

Facilities Costs: Facilities costs depend on both the process and the resource. Five approaches are used to calculate the facilities costs for the project.

For undiscovered and developing natural gas projects:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * PATN_{iyr} * XPP1) \quad (2\text{-}64)$$

For existing natural gas fields:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * (PATDEV_{IRES,iyr, itech}) * XPP1) \quad (2\text{-}65)$$

For undiscovered continuous crude oil:

$$FACCOST_{iyr} = FACCOST_{iyr} + (NPR\_W * PATN_{iyr} * XPP1) \quad (2\text{-}66)$$

For existing crude oil fields:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * (PATDEV_{IRES,iyr, itech}) * XPP4) \quad (2\text{-}67) \\ &+ (PSI\_W * PATDEV_{IRES,iyr, itech} * XPP3) \\ &+ (FAC\_W * PATDEV_{IRES,iyr, itech} * (XPP1 + XPP2)) \end{aligned}$$

For undiscovered conventional crude oil and EOR/ASR projects:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * PATN_{iyr} * XPP4) \quad (2\text{-}68) \\ &+ (PSI\_W * PATN_{iyr} * XPP3) + (FAC\_W * PATN_{iyr} * (XPP1 + XPP2)) \end{aligned}$$

where

IYR = Year
IRES = Project index number
ITECH = Technology case
PATN = Number of patterns initiated each year for the technology case being evaluated
PATDEV = Number of patterns initiated each year for base and advanced technology cases
XPP1 = Number of new production wells drilled per pattern
XPP2 = Number of new injection wells drilled per pattern
XPP3 = Number of producers converted to injectors per pattern
XPP4 = Number of primary wells converted to secondary wells per pattern
FAC_W = Crude oil well facilities upgrade cost
NPR_W = Cost to equip a new producer
PSW_W = Cost to convert a primary well to a secondary well
PSI_W = Cost to convert a production well to an injection well
FWC_W = Natural gas well facilities cost
FACCOST = Annual facilities cost for the well

Injectant Cost Added to Operating and Maintenance: The cost of injectant is calculated and added to the operating and maintenance costs.

$$INJ_{iyr} = INJ_{iyr} + INJ\_OAM1 * WATINJ_{iyr} \quad (2\text{-}69)$$

where

IYR = Year

INJ = Annual injection cost
INJ_OAM1 = Process specific cost of injection ($/Bbl)
WATINJ = Annual project level water injection

Fixed Annual Operating Costs for Crude Oil:

For CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + OPSEC\_W * SUMP_{iyr} \quad (2\text{-}70)$$

For undiscovered conventional crude oil:

Fixed annual operating costs for secondary oil wells are assumed to be zero.

For all crude oil processes except CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + (OMO\_W * XPATN_{iyr}) + (OPSEC\_W * XPATN_{iyr}) \quad (2\text{-}71)$$

Fixed Annual Operating Costs for Natural Gas:

For existing natural gas fields:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) \quad (2\text{-}72)$$

For undiscovered and developing natural gas resources:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) * XPP1 \quad (2\text{-}73)$$

where,

AOAM = Annual fixed operating an maintenance costs
IYR = Year
SUMP = Total cumulative patterns initiated
OPSEC_W = Fixed annual operating costs for secondary oil wells
OMO_W = Fixed annual operating costs for crude oil wells
FOAMG_W = Fixed annual operating costs for natural gas wells
OAM_M = Energy elasticity factor for operating and maintenance costs
XPATN = Annual number of active patterns
XPP1 = Number of producing wells drilled per pattern

Variable Operating Costs:

$$OAM_{iyr} = OAM_{iyr} + (OILPROD_{iyr} * OIL\_OAM1 * OAM\_M_{iyr}) + (GASPROD_{iyr} * GAS\_OAM1 * OAM\_M_{iyr}) + (WATPROD_{iyr} * WAT\_OAM1 * OAM\_M_{iyr}) \quad (2\text{-}74)$$

$$STIM_{iyr} = STIM_{iyr} + (0.2 * STIM\_W * XPATN_{iyr} * XPP1) \tag{2-74}$$

<u>For infill drilling:</u> Injectant costs are zero.

$$OAM_{iyr} = OAM_{iyr} + INJ_{iyr} \tag{2-75}$$

where

OAM = Annual variable operating and maintenance costs
OILPROD = Annual project level crude oil production
GASPROD = Annual project level natural gas production
WATPROD = Annual project level water injection
OIL_OAM1 = Process specific cost of crude oil production ($/Bbl)
GAS_OAM1 = Process specific cost of natural gas production ($/Mcf)
WAT_OAM1 = Process specific cost of water production ($/Bbl)
OAM_M = Energy elasticity factor for operating and maintenance costs
STIM = Project stimulation costs
STIM_W = Well stimulation costs
INJ = Cost of injection
XPATN = Annual number of active patterns
IYR = Year
XPP1 = Number of producing wells drilled per pattern

Cost of Compression (Natural Gas Processes):
<u>Installation costs:</u>

$$COMP_{IYR} = COMP_{IYR} + (COMP\_W*PATN_{IYR}*XPP1) \tag{2-76}$$

<u>O&M cost for compression:</u>

$$OAM\_COMP_{IYR} = OAM\_COMP_{IYR} + (GASPROD_{IYR} * COMP\_OAM *OAM\_M_{IYR}) \tag{2-77}$$

where

COMP = Cost of installing natural gas compression equipment
COMP_W = Natural gas compression cost
PATN = Number of patterns initiated each year
IYR = Year
XPP1 = Number of producing wells drilled per pattern
OAM_COMP = Operating and maintenance costs for natural gas compression
GASPROD = Annual project level natural gas production
COMP_OAM = Compressor O & M costs
OAM_M = Energy elasticity factor for operating and maintenance costs

Process Dependent Costs

Process-specific facilities and capital costs are calculated at the project level.

Facilities Costs

Profile Model: The facilities cost of a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWHP * \left(\frac{RMAX}{365}\right) \qquad (2\text{-}78)$$

where

FACCOST$_1$ = First year of project facilities costs
PWHP = Produced water handling plant multiplier
RMAX = Maximum annual water injection rate

Polymer Model: The facilities cost for a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWP\_F \qquad (2\text{-}79)$$

where

FACCOST$_1$ = First year of project facilities costs
PWP_F = Produced water handling plant

Advanced CO$_2$: Other costs added to the facilities costs include the facilities cost for a CO$_2$ handling plant and a recycling plant, the O&M cost for a CO$_2$ handling plant and recycling plant, injectant cost, O&M and fixed O&M costs for a CO$_2$ handling plant and a recycling plant. If the plant is developed in a single stage, the costs are added to the first year of the facilities costs. If a second stage is required, the additional costs are added to the sixth year of facilities costs.

$$FACCOST1 = FACCOST1 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000 \qquad (2\text{-}80)$$

$$FACCOST6 = FACCOST6 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000$$

$$INJ_{iyr} = INJ_{iyr} + (TOTINJ_{iyr} - TORECY_{iyr}) * CO2COST \qquad (2\text{-}81)$$

$$OAM_{iyr} = OAM_{iyr} + (OAM\_M_{iyr} * TORECY_{iyr}) * (CO2OAM + PSW\_W * 0.25) \qquad (2\text{-}82)$$

$$FOAM_{iyr} = (FOAM_{iyr} + TOTINJ_{iyr}) * 0.40 * FCO2 \qquad (2\text{-}83)$$

$$TORECY\_CST_{iyr} = TORECY\_CST_{iyr} + (TORECY_{iyr} * CO2OAM2 * OAM\_M_{iyr}) \qquad (2\text{-}84)$$

where

IYR = Year
RMAX = Maximum annual volume of recycled CO$_2$

CO2OAM = O & M cost for CO_2 handling plant
CO2OAM2 = The O & M cost for the project's CO_2 injection plant
CO2RK, CO2RB = CO_2 recycling plant cost coefficients
INJ = Cost of purchased CO_2
TOTINJ = Annual project level volume of injected CO_2
TORECY = Annual project level CO_2 recycled volume
CO2COST = Cost of CO_2 (\$/mcf)
OAM = Annual variable operating and maintenance costs
OAM_M = Energy elasticity factor for operating and maintenance costs
FOAM = Fixed annual operating and maintenance costs
FCO2 = Energy elasticity factor for CO_2
FACCOST = Annual project facilities costs
TORECY_CST = The annual cost of operating the CO_2 recycling plant

Steam Model: Facilities and O&M costs for steam generators and recycling.

Recalculate the facilities costs: Facilities costs include the capital cost for injection plants, which is based upon the OOIP of the project, the steam recycling plant, and the steam generators required for the project.

$$FACCOST1 = FACCOST1 + \left(\frac{OOIP*0.1*2.0*APAT}{TOTPAT}\right) + (RECY\_WAT * RMAXWAT + RECY\_OIL * RMAXOIL) + (STMMA * TOTPAT * PATSIZE) + (IGEN_{iyr} - IG\ )* STMGA \tag{2-85}$$

$$OAM_{iyr} = OAM_{iyr} + (WAT\_OAM1 * WATPROD_{iyr} * OAM\_M_{iyr}) + (OIL\_OAM1 * OILPROD_{iyr} * OAM\_M_{iyr}) + (INJ\_OAM1 * WATINJ_{iyr} * OAM\_M_{iyr}) \tag{2-86}$$

where

IYR = Year
IGEN = Number of active steam generators each year
IG = Number of active steam generators in previous year
FACCOST = Annual project level facilities costs
RMAXWAT = Maximum daily water production rate
RMAXOIL = Maximum daily crude oil production rate
APAT = Number of developed patterns
TOTPAT = Total number of patterns in the project
OOIP = Original oil in place (mmbbl)
PATSIZE = Pattern size (acres)
STMMA = Unit cost for steam manifolds
STMGA = Unit cost for steam generators
OAM = Annual variable operating and maintenance costs
OAM_M = Energy elasticity factor for operating and maintenance costs
WAT_OAM1 = Process specific cost of water production (\$/Bbl)
OIL_OAM1 = Process specific cost of crude oil production (\$/Bbl)

INJ_OAM1 = Process specific cost of water injection ($/Bbl)
OILPROD = Annual project level crude oil production
WATPROD = Annual project level water production
WATINJ = Annual project level water injection
RECY_WAT = Recycling plant cost – water factor
RECY_OIL = Recycling plant cost – oil factor

Operating and Maintenance Cost

This subroutine calculates the process specific O&M costs.

Profile Model: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{iyr} + \frac{OAM\_M_{iyr} * TOTINJ_{iyr} * POLYCOST}{1000} \qquad (2\text{-}87)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \qquad (2\text{-}88)$$

where

IYR = Year
MAX_YR = Maximum number of years
INJ = Annual Injection cost
OAM_M = Energy elasticity factor for operating and maintenance cost
TOTINJ = Annual project level injectant injection volume
POLYCOST = Polymer cost
OAM = Annual variable operating and maintenance cost
XPATN = Number of active patterns
PSI_W = Cost to convert a primary well to an injection well

Polymer: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{IYR} + \frac{TOTINJ_{iyr} * POLYCOST}{1{,}000} \qquad (2\text{-}89)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \qquad (2\text{-}90)$$

where

IYR = Year
MAX_YR = Maximum number of years
INJ = Annual Injection cost
TOTINJ = Annual project level injectant injection volume
POLYCOST = Polymer cost
OAM = Annual variable operating and maintenance cost
XPATN = Number of active patterns
PSI_W = Cost to convert a primary well to an injection well

Waterflood: Add the O&M costs of water injected as well as the cost to convert a primary well to an injection well.

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}91)$$

where

IYR = Year
MAX_YR = Maximum number of years
OAM = Annual variable operating and maintenance cost
XPATN = Number of active patterns
PSI_W = Cost to convert a primary well to an injection well

Existing crude oil fields and reservoirs: Since no new drilling or major investments are expected for decline, facilities and drilling costs are zeroed out.

$$OAM_{iyr} = OAM_{iyr} + ((OIL\_OAM1 * OILPROD_{iyr}) + (GAS\_OAM1 * GASPROD_{iyr}) + (WAT\_OAM1 * WATPROD_{iyr})) * OAM\_M_{iyr} \quad (2\text{-}92)$$

$$AOAM_{iyr} = AOAM_{iyr} + \left(\frac{OPSEC\_W * OAM\_M_{iyr} * SUMP_{iyr}}{5} \right) \quad (2\text{-}93)$$

where

IYR = Year
OILPROD = Annual project level crude oil production
GASPROD = Annual project level natural gas production
WATPROD = Annual project level water production
OIL_OAM1 = Process specific cost of crude oil production ($/Bbl)
GAS_OAM1 = Process specific cost of natural gas production ($/Mcf)
WAT_OAM1 = Process specific cost of water production ($/Bbl)
OAM_M = Energy elasticity factor for operating and maintenance costs
OPSEC_W = Fixed annual operating cost for secondary well operations
SUMP = Cumulative patterns developed
AOAM = Fixed annual operating and maintenance costs
OAM = Variable annual operating and maintenance costs

Overhead Costs: : General and Administrative (G&A) costs on capitalized and expensed items, which consist of administration, accounting, contracting and legal fees/expenses for the project, are calculated according to the following equations:

$$GNA\_EXP_{itech} = GNA\_EXP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}94)$$
$$GNA\_CAP_{itech} = GNA\_CAP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}95)$$

where

ITECH = Technology case (base and advanced) number
GNA_EXP = The G&A rate applied to expensed items for the project
GNA_CAP = The G&A rate applied to capitalized items for the project
CHG_GNA_FAC = Technology case specific change in G&A rates

Timing

Overview of Timing Module

The timing routine determines which of the exploration and EOR/ASR projects are eligible for development in any particular year. Those that are eligible are subject to an economic analysis and passed to the project sort and development routines. The timing routine has two sections. The first applies to exploration projects while the second is applied to EOR/ASR and developing natural gas projects.

Figure 2-9 provides the overall logic for the exploration component of the timing routine. For each project regional crude oil and natural gas prices are obtained. The project is then examined to see if it has previously been timed and developed. The timed projects are no longer available and thus not considered.

The model uses four resource access categories for the undiscovered projects:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

Each project has been assigned to a resource access category. If the access category is not available in the year evaluated, the project fails the resource access check.

After the project is evaluated, the number of considered projects is increased. Figure 2-10 shows the timing logic applied to the EOR/ASR projects as well as the developing natural gas projects.

Before the economics are evaluated, the prices are set and the eligibility is determined. The following conditions must be met:

- Project has not been previously timed
- Project must be eligible for timing, re-passed the economic pre-screening routine
- Corresponding decline curve project must have been timed. This does not apply to the developing natural gas projects.

If the project meets all of these criteria, then it is considered eligible for economic analysis. For an EOR/ASR project to be considered for timing, it must be within a process specific EOR/ASR development window. These windows are listed in Table 2-4.

Table 2-4: EOR/ASR Eligibility Ranges

Process	Before Economic Limit	After Economic Limit
CO_2 Flooding	After 2009	10 Years
Steam Flooding	5 Years	10 Years
Polymer Flooding	5 Years	10 Years
Infill Drilling	After 2009	7 Years
Profile Modification	5 Years	7 Years
Horizontal Continuity	5 Years	7 Years
Horizontal Profile	5 Years	7 Years
Waterflood	4 Years	6 Years

The economic viability of the eligible projects is then evaluated. A different analytical approach is applied to CO_2 EOR and all other projects. For non-CO_2 EOR projects the project is screened for applicable technology levers, and the economic analysis is conducted. CO_2 EOR projects are treated differently because of the different CO_2 costs associated with the different sources of industrial and natural CO_2.

For each available source, the economic variables are calculated and stored. These include the source of CO_2 and the project's ranking criterion.

Detailed description of timing module

Exploration projects: The first step in the timing module is to determine which reservoirs are eligible to be timed for conventional and continuous exploration. Prior to evaluation, the constraints, resource access, and technology and economic levers are checked, and the technology case is set.

Calculate economics for EOR/ASR and developing natural gas projects:
This section determines whether an EOR/ASR or developing natural gas project is eligible for economic analysis and timing. The following resources are processes considered in this step.
EOR Processes:

- CO_2 Flooding
- Steam Flooding
- Polymer Flooding
- Profile Modification

ASR Processes:

- Water Flooding
- Infill Drilling
- Horizontal Continuity
- Horizontal Profile

Developing natural gas

- Tight Gas
- Shale Gas
- Coalbed Methane

A project is eligible for timing if the corresponding decline curve project has previously been timed and the year of evaluation is within the eligibility window for the process, as listed in table 2-4.

Project Ranking: Sorts exploration and EOR/ASR projects which are economic for timing. The subroutine matches the discovery order for undiscovered projects and sorts the others by ranking criterion. The criteria include

- Net present value
- Investment efficiency
- Rate of return
- Cumulative discounted after tax cashflow

Selection and Timing: Times the exploration and EOR/ASR projects which are considered in that given year.

Project Selection

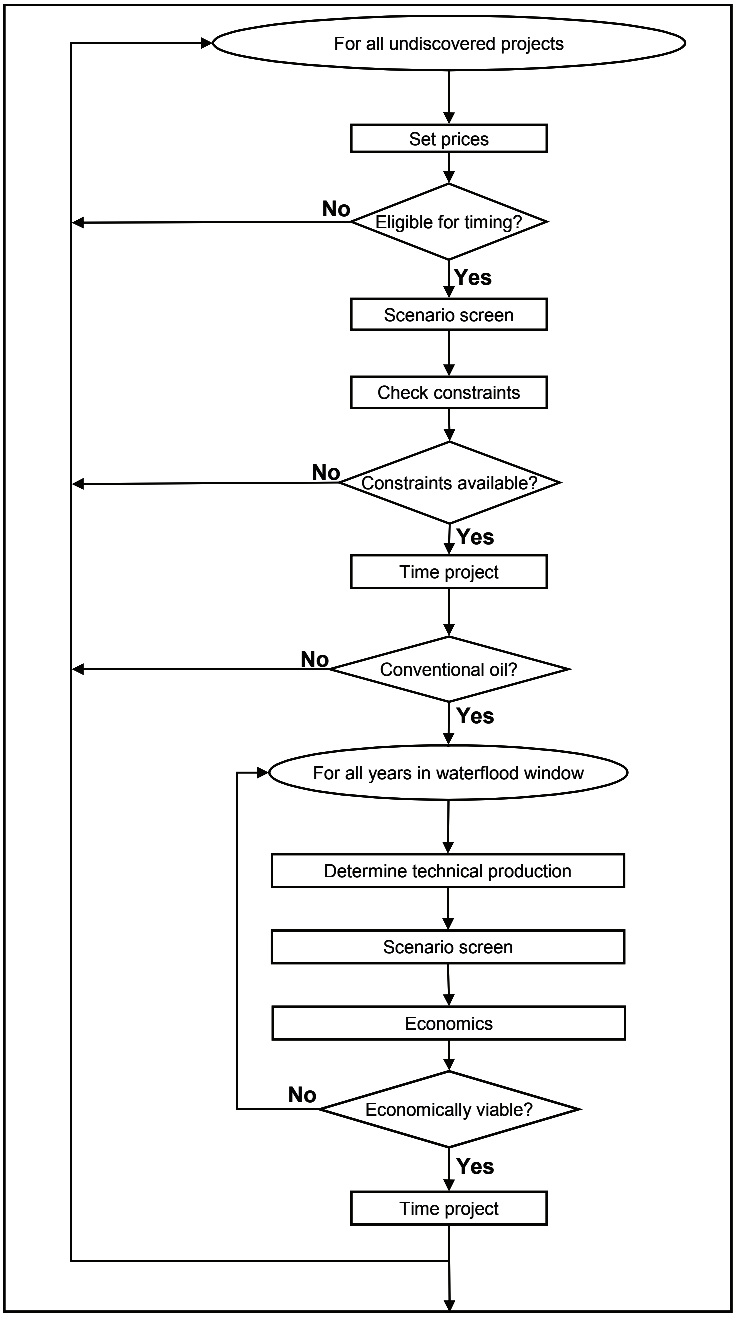
The project selection subroutine determines which exploration, EOR/ASR and developing natural gas projects will be modeled as developed in each year analyzed. In addition, the following development decisions are made:

- Waterflood of conventional undiscovered crude oil projects
- Extension of CO_2 floods as the total CO_2 injected is increased from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV

Overview of Project Selection

The project selection subroutine evaluates undiscovered projects separate from other projects. The logic for the development of exploration projects is provided in figure 2-9.

Figure 2-9: Selecting Undiscovered Projects



As illustrated in the figure the prices are set for the project before its eligibility is checked. Eligibility has the following requirements:

- Project is economically viable
- Project is not previously timed and developed

The projects which are eligible are screened for applicable technologies which impact the drilling success rates. The development constraints required for the project are checked against those that are available in the region.

If sufficient development resources are available, the project is timed and developed. As part of this process, the available development constraints are adjusted, the number of available accumulations is reduced and the results are aggregated. If no undiscovered accumulations remain, then the project is no longer eligible for timing. The projects that are eligible, economically viable, and undeveloped due to lack of development resources, are considered again for future projection years. If the project is conventional crude oil, it is possible to time a waterflood project.

The model evaluates the waterflood potential in a window centered upon the end of the economic life for the undiscovered project. For each year of that window, the technical production is determined for the waterflood project, applicable technology and economic levers are applied, and the economics are considered. If the waterflood project is economic, it is timed. This process is continued until either a waterflood project is timed or the window closes.

The second component of the project selection subroutine is applicable to EOR/ASR projects as well as the developing natural gas projects. The major steps applied to these projects are detailed in figures 2-10 and 2-11.

As seen in the flowchart, the prices are set for the project and the eligibility is checked. As with the undiscovered projects, the subroutine checks the candidate project for both economic viability and eligibility for timing. Afterwards, the project is screened for any applicable technology and economic levers.

If the project is eligible for CO_2 EOR, the economics are re-run for the specific source of CO_2. Afterwards, the availability of resource development constraints is checked for the project. If sufficient drilling and capital resources are available, the project preferences are checked.

The project preferences are rules which govern the competition between projects and selection of projects; these rules are listed below:

- CO_2 EOR and infill drilling are available after 2010
- Profile modification becomes available after 2011
- The annual number of infill drilling and profile modification projects is limited
- Horizontal continuity can compete against any other process except steam flood
- Horizontal profile can compete against any other process except steam flood or profile modification
- Polymer flooding cannot compete against any other process

If the project meets the technology preferences, then it is timed and developed. This process is different for CO_2 EOR and all other processes.

Figure 2-10: Selecting EOR/ASR projects

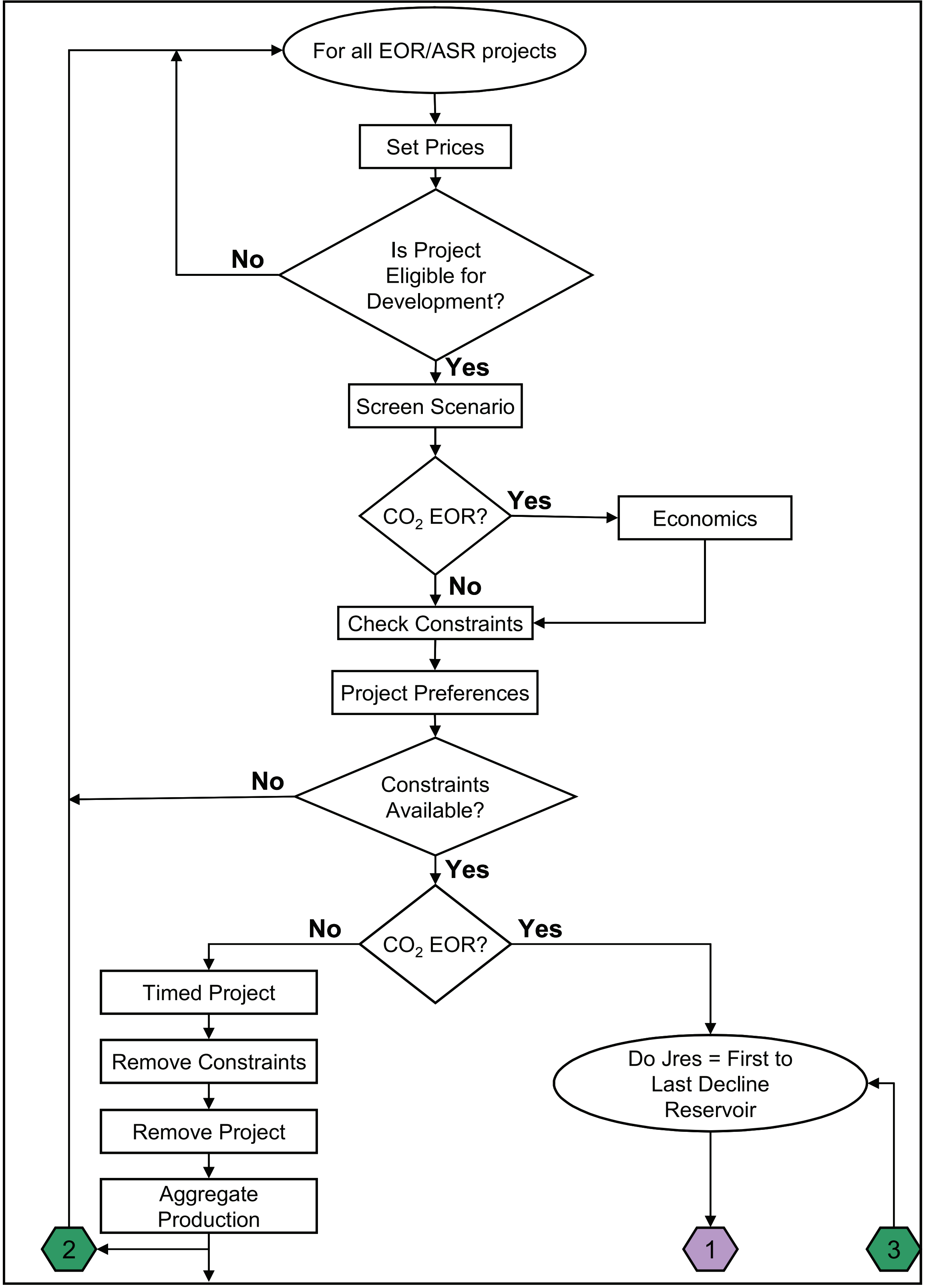
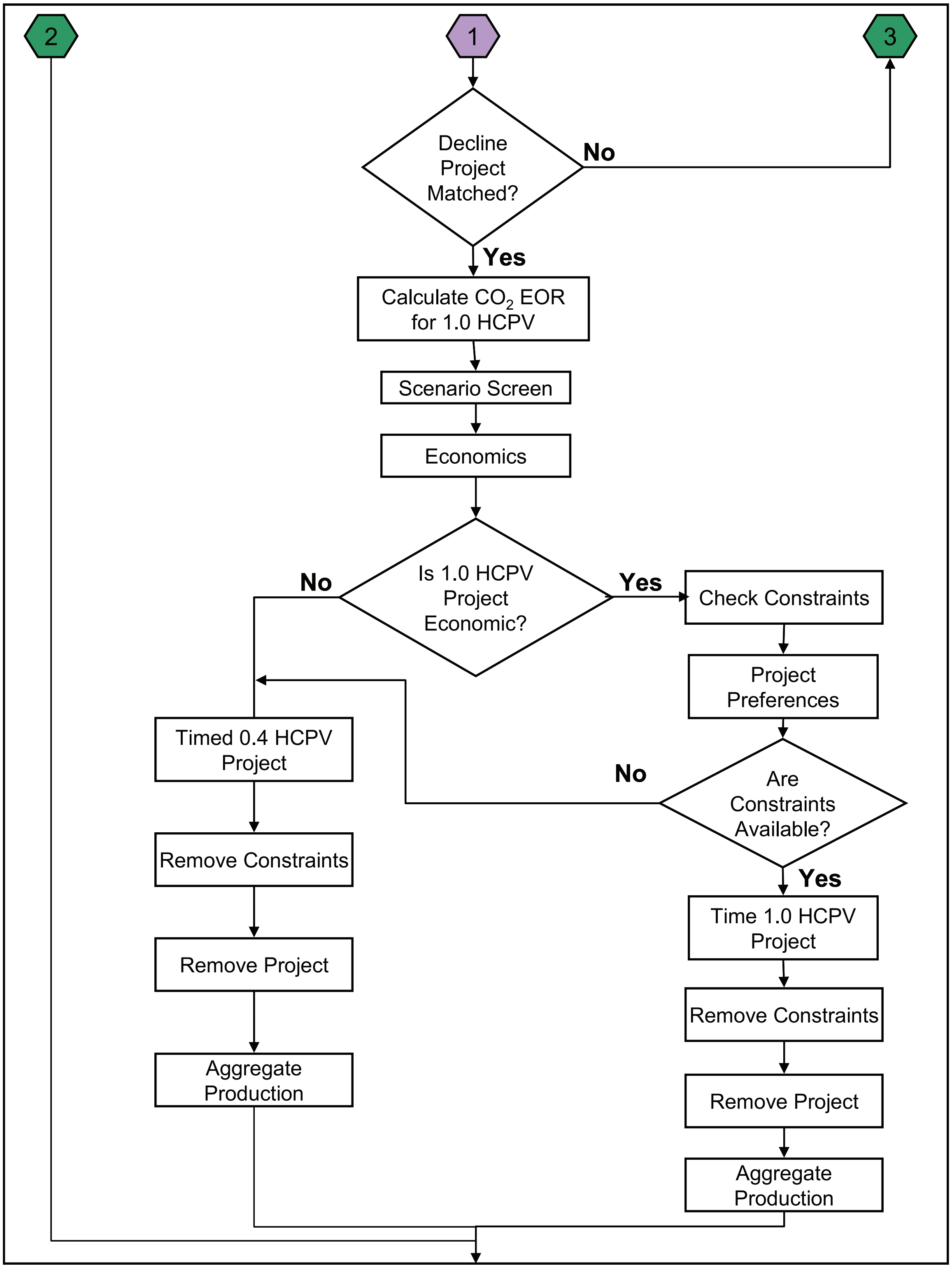


Figure 2-11: Selecting EOR/ASR projects, Continued



For non-CO_2 projects, the constraints are adjusted, the project is removed from the list of eligible projects, and the results are aggregated. It is assumed that most EOR/ASR processes are mutually exclusive and that a reservoir is limited to one process. There are a few exceptions:

- CO_2 EOR and infill drilling can be done in the same reservoir
- CO_2 EOR and horizontal continuity can be done in the same reservoir

For CO_2 EOR projects, a different methodology is used at this step: the decision to increase the total CO_2 injection from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV is made. The model performs the following steps, illustrated in figure 2-10 and continued in figure 2-11.

The CO_2 EOR project is matched to the corresponding decline curve project. Using the project-specific petro-physical properties, the technical production and injection requirements are determined for the 1.0 HCPV project. After applying any applicable technology and economic levers, the model evaluates the project economics. If the 1.0 HCPV project is not economically viable, then the 0.4 HCPV project is timed. If the 1.0 HCPV project is viable, the constraints and project preferences are checked. Assuming that there are sufficient development resources, and competition allows for the development of the project, then the model times the 1.0 HCPV project. If sufficient resources for the 1.0 HCPV project are not available, the model times the 0.4 HCPV project.

Detailed description of project selection

The project selection subroutine analyzes undiscovered crude oil and natural gas projects. If a project is economic and eligible for development, the drilling and capital constraints are examined to determine whether the constraints have been met. The model assumes that the projects for which development resources are available are developed.

Waterflood processing may be considered for undiscovered conventional crude oil projects. The waterflood project will be developed in the first year it is both eligible for implementation and the waterflood project is economically viable.

EOR/ASR Projects

When considering whether a project is eligible for EOR/ASR processing, the model first checks the availability of sufficient development resources are available. Based on the project economics and projected availability of development resources, it also decides whether or not to extend injection in CO_2 EOR projects from 0.4 HCPV to 1.0 HCPV.

If the 1.0 HCPV is economic but insufficient resources are available, the 0.4 HCPV project is selected instead. If the 1.0 HCPV project is uneconomic, the 0.4 HCPV project is selected.

Constraints

Resource development constraints are used during the selection of projects for development in order to mimic the infrastructure limitations of the oil and gas industry. The model assumes that only the projects that do not exceed the constraints available will be developed.

Types of constraints modeled

The development constraints represented in the model include drilling footage availability, rig depth rating, capital constraints, demand for natural gas, carbon dioxide volumes, and resource access.

In the remainder of this section, additional details will be provided for each of these constraints.

Drilling: Drilling constraints are bounding values used to determine the resource production in a given region. OLOGSS uses the following drilling categories:

- Developmental crude oil – applied to EOR/ASR projects
- Developmental natural gas – applied to developing natural gas projects
- Horizontal drilling – applied to horizontal wells
- Dual use – available for either crude oil or natural gas projects
- Conventional crude oil exploration – applied to undiscovered conventional crude oil projects
- Conventional natural gas exploration – applied to undiscovered conventional natural gas projects
- Continuous crude oil exploration – applied to undiscovered continuous crude oil projects
- Continuous natural gas exploration – applied to undiscovered continuous natural gas projects

Except for horizontal drilling, which is calculated as a fraction of the national developmental crude oil footage, all categories are calculated at the national level and apportioned to the regional level. Horizontal drilling is at the national level.

The following equations are used to calculate the national crude oil development drilling. The annual footage available is a function of lagged five year average crude oil prices and the total growth in drilling.

The total growth in drilling is calculated using the following algorithm.

<u>For the first year:</u>

$$\mathrm{TOT\_GROWTH} = 1.0 * \left(1.0 + \frac{\mathrm{DRILL\_OVER}}{100}\right) \tag{2-96}$$

<u>For the remaining years:</u> (2-97)

$$\mathrm{TOT\_GROWTH} = \left(\left(\mathrm{TOT\_GROWTH} * \left(1.0 + \frac{\mathrm{RGR}}{100}\right)\right) - \left(\mathrm{TOT\_GROWTH} * \left(1.0 + \frac{\mathrm{RGR}}{100}\right)\right) * \left(\frac{\mathrm{RRR}}{100}\right)\right) * \left(1.0 * \frac{\mathrm{DRILL\_OVER}}{100}\right)$$

Reviewers note: The equation above would be clearer if it were written as

where

IYR = Year evaluated
MAX_YR = Maximum number of years
TOT_GROWTH = Annual growth change for drilling at the national level (fraction)
DRILL_OVER = Percent of drilling constraint available for footage over run
RGR = Annual rig development rate (percent)
RRR = Annual rig retirement rate (percent)

The national level crude oil and natural gas development footage available for drilling is calculated using the following equations. The coefficients for the drilling footage equations were estimated by least squares using model equations 2.B-16 and 2.B-17 in Appendix 2.B.

$$NAT\_OIL_{IYR} = (OILA0 + OILA1 * OILPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * OIL\_ADJ_{IYR} \quad (2\text{-}98)$$

$$NAT\_GAS_{IYR} = (GASA0 + GASA1 * GASPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * GAS\_ADJ_{IYR} \quad (2\text{-}99)$$

where

IYR = Year evaluated
TOT_GROWTH = Final calculated annual growth change for drilling at the national level
NAT_OIL NAT_GAS = National development footage available (Thousand Feet)
OILA0,1 GASA0,1 = Footage equation coefficients
OILPRICED GASPRICED = Annual prices used in drilling constraints, five year average
TOTMUL = Total drilling constraint multiplier
OIL_ADJ GAS_ADJ = Annual crude oil, natural gas developmental drilling availability factors

After the available footage for drilling is calculated at the national level, regional allocations are used to allocate the drilling to each of the OLOGSS regions. The drilling which is not allocated, due to the “drill_trans” factor, is available in any region and represents the drilling which can be transferred among regions. The regional allocations are then subtracted from the national availability.

$$REG\_OIL_{j,iyr} = NAT\_OIL_{IYR} * \left(\frac{PRO\_REGOIL_{J}}{100} \right) * \left(1.0 - \frac{DRILL\_TRANS}{100} \right) \quad (2\text{-}100)$$

where

J = Region number
IYR = Year

REG_OIL = Regional development oil footage (Thousand Feet) available in a specified region
NAT_OIL = National development oil footage (Thousand Feet). After allocation, the footage transferrable among regions.
PRO_REGOIL = Regional development oil footage allocation (percent)
DRILL_TRANS = Percent of footage that is transferable among regions

Footage Constraints: The model determines whether there is sufficient footage available to drill the complete project. The drilling constraint is applied to all projects. Footage requirements are calculated in two stages: vertical drilling and horizontal drilling. The first well for an exploration project is assumed to be a wildcat well and uses a different success rate than the other wells in the project. The vertical drilling is calculated using the following formula.

<u>For non-exploration projects:</u>

$$\begin{aligned} FOOTREQ_{ii} = {} & (DEPTH_{itech} * (1.0 + SUC\_RATEKD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} \\ & * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} \\ & * PATDEV_{irs,ii-itiimeyr+1,itech}) * 0.5 * ATOTCONV_{irs,itech} \end{aligned} \tag{2-101}$$

<u>For exploration projects:</u>

For the first year of the project (2-102)

$$\begin{aligned} FOOTREQ_{ii} = {} & (DEPTH_{itech} * (1.0 + SUC\_RATEUE_{itech})) * (ATOTPROD_{irs,itech} \\ & + ATOTINJ_{irs,itech}) + (0.5 * ATOTCONV_{irs,itech}) + (DEPTH_{itech} \\ & * (1.0 + SUC\_RATEUD_{itech})) * (PATDEV_{irs,ii-itimeyr+1,itech} - 1 \\ & * ATOTPROD_{irs,itech} + ATOTINJ_{ir,itech} + 0.5 * ATOTCONV_{irs,itech}) \end{aligned}$$

For all other project years (2-103)

$$\begin{aligned} FOOTREQ_{ii} = {} & (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} \\ & * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} \\ & * PATDEV_{irs,ii-itimeyr+1,itech} * 0.5 * ATOTCONV_{irs,itech}) \end{aligned}$$

where

irs = Project index number
itech = Technology index number
itimeyr = Year in which project is evaluated for development
ii = Year evaluated
FOOTREQ = Footage required for drilling (Thousand Feet)
DEPTH = Depth of formation (Feet)
SUC_RATEKD = Success rate for known development
SUC_RATEUE = Success rate for undiscovered exploration (wildcat)
SUC_RATEUD = Success rate for undiscovered development
PATDEV = Annual number of patterns developed for base and advanced technology
ATOTPROD = Number of new producers drilled per pattern
ATOTINJ = Number of new injectors drilled per patterns
ATOTCONV = Number of conversions from producing to injection wells per pattern

Add Laterals and Horizontal Wells: The lateral length and the horizontal well length are added to the footage required for drilling.

$$\text{FOOTREQii} = \text{FOOTREQii} + (\text{ALATNUM}_{irs,itech} * \text{ALATLEN}_{irs,itech} * (1.0 + \text{SUC\_RATEKD}_{itech}) * \text{PATDEV}_{irs,ii-itimeyr+1,itech}) \quad (2\text{-}104)$$

where

irs = Project index number
itech = Technology index number
itimeyr = Year in which project is evaluated for development
ii = Year evaluated
FOOTREQ = Footage required for drilling (Feet)
ALATNUM = Number of laterals
ALATLEN = Length of laterals (Feet)
SUC_RATEKD = Success rate for known development
PATDEV = Annual number of patterns developed for base and advanced technology

After determining the footage requirements, the model calculates the footage available for the project. The available footage is specific to the resource, the process, and the constraint options which have been specified by the user. If the footage required to drill the project is greater than the footage available then the project is not feasible.

Rig depth rating: The rig depth rating is used to determine whether a rig is available which can drill to the depth required by the project. OLOGSS uses the nine rig depth categories provided in table 2-5.

Table 2-5 Rig Depth Categories

Depth Category	Minimum Depth (Ft)	Maximum Depth (Ft)
1	1	2,500
2	2,501	5,000
3	5,001	7,500
4	7,501	10,000
5	10,001	12,500
6	12,501	15,000
7	15,001	17,500
8	17,251	20,000
9	20,001	Deeper

The rig depth rating is applied at the national level. The available footage is calculated using the following equation.

$$\text{RDR\_FOOTAGE}_{j,\,iyr} = (\text{NAT\_TOT}_{iyr} + \text{NAT\_EXP}_{iyr} + \text{NAT\_EXPG}_{iyr}) * \frac{RDR_j}{100} \quad (2\text{-}106)$$

where

J = Rig depth rating category
IYR = Year
RDR_FOOTAGE = Footage available in this interval (K Ft)

NAT_TOT = Total national developmental (crude oil, natural gas, and horizontal) drilling footage available (Thousand feet)
NAT_EXPG = National gas exploration drilling constraint
NAT_EXP = Total national exploration drilling footage available (Thousand feet)
RDR_j = Percentage of rigs which can drill to depth category j

Capital: Crude oil and natural gas companies use different investment and project evaluation criteria based upon their specific cost of capital, the portfolio of investment opportunities available, and their perceived technical risks. OLOGSS uses capital constraints to mimic limitations on the amount of investments the oil and gas industry can make in a given year. The capital constraint is applied at the national level.

Natural Gas Demand: Demand for natural gas is calculated at the regional level by the NGTDM and supplied to OLOGSS.

Carbon Dioxide: For CO_2 miscible flooding, availability of CO_2 gas from natural and industrial sources is a limiting factor in developing the candidate projects. In the Permian Basin, where the majority of the current CO_2 projects are located, the CO_2 pipeline capacity is a major concern.

The CO_2 constraint in OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are ammonia plants, hydrogen plants, existing and planned ethanol plants, cement plants, refineries, fossil fuel power plants, and new IGCC plants.

Technology and market constraints prevent the total volumes of CO_2 produced from becoming immediately available. The development of the CO_2 market is divided into 3 periods:
1) technology R&D, 2) infrastructure construction, and 3) market acceptance. The capture technology is under development during the R&D phase, and no CO_2 produced by the technology is assumed available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no CO_2 is assumed available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 are assumed to become available.

The maximum CO_2 available is achieved when the maximum percentage of the industry that will adopt the technology has adopted it. This provides an upper limit on the volume of CO_2 that will be available. The graph below provides the annual availability of CO_2 from ammonia plants. Availability curves were developed for each source of industrial, as well as natural CO_2.

CO_2 constraints are calculated at the regional level and are source specific.

Resource Access: Restrictions on access to Federal lands constrain the development of undiscovered crude oil and natural gas resources. OLOGSS uses four resource access categories:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

The percentage of the undiscovered resource in each category was estimated using data from the Department of Interior's Basin Inventories of Onshore Federal Land's Oil and Gas Resources.

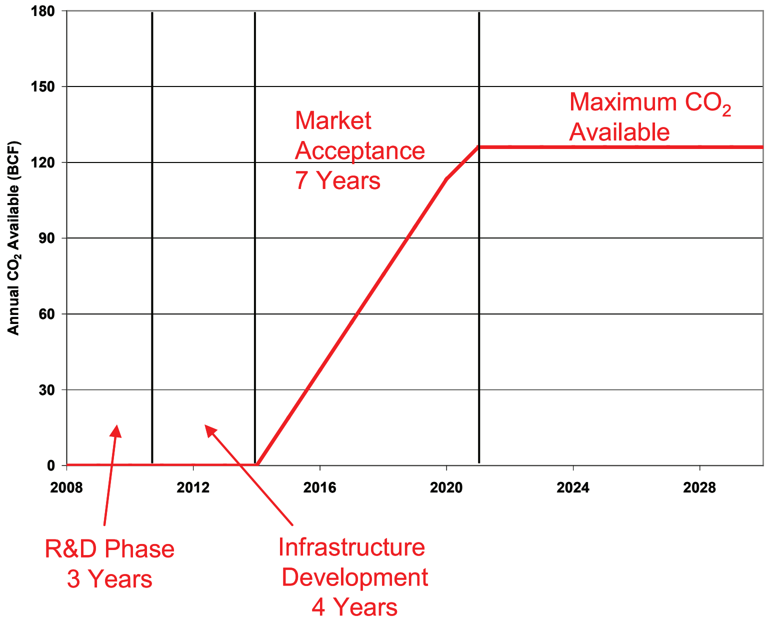


Figure 2-12: CO2 Market Acceptance Curve

Technology

Research and development programs are designed to improve technology to increase the amount of resources recovered from crude oil and natural gas fields. Key areas of study include methods of increasing production, extending reserves, and reducing costs. To optimize the impact of R & D efforts, potential benefits of a new technology are weighed against the costs of research and development. OLOGSS has the capability to model the effects of R & D programs and other technology improvements as they impact the production and economics of a project. This is done in two steps: (1) modeling the implementation of the technology within the oil and gas industry and (2) modeling the costs and benefits for a project that applies this technology.

Impact of technology on economics and recovery

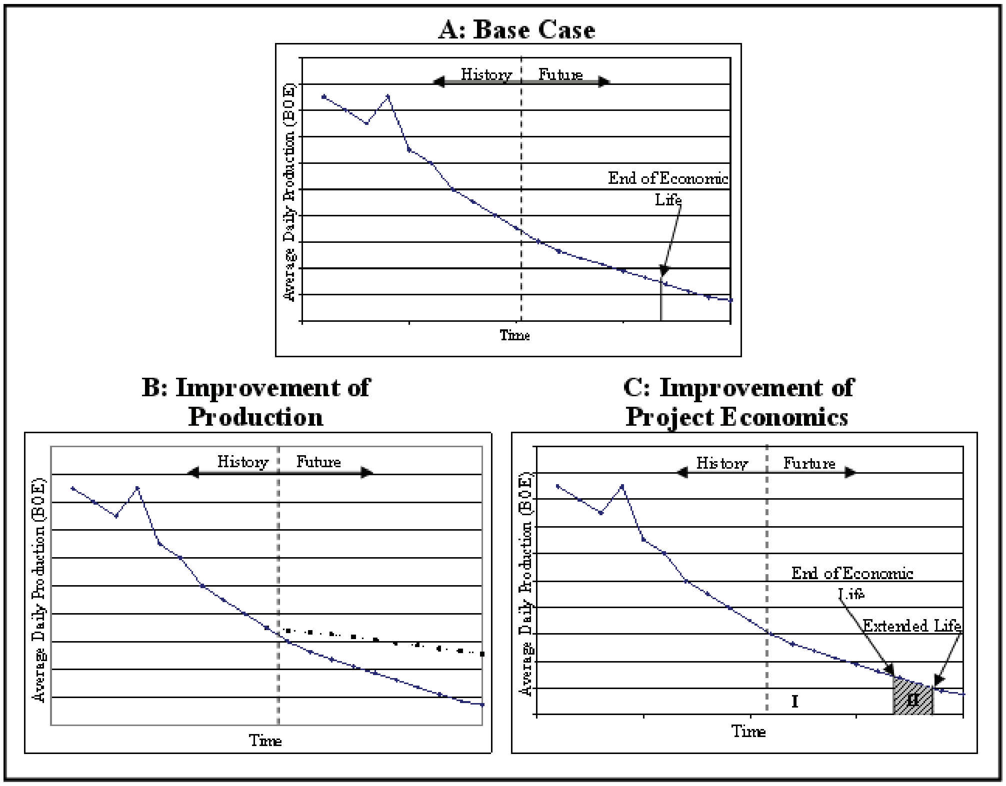
Figure 2-13 illustrates the effects of technology improvement on the production and project economics of a hypothetical well. The graphs plot the daily average production, projected by decline analysis, over the life of the project. Each graph represents a different scenario: (A) base case, (B) production improvement, and (C) economic improvement.

Graph A plots the production for the base case. In the base case, no new technology is applied to the project. The end of the project's economic life, the point at which potential revenues are less than costs of further production, is indicated. At that point, the project would be subject to reserves-growth processes or shut in.

Graph B plots the production for the base case and a production-increasing technology such as skin reduction. The reduction in skin, through well-bore fracturing or acidizing, increases the daily production flow rate. The increase in daily production rate is shown by the dotted line in graph B. The outcome of the production-increasing technology is reserves growth for the well. The amount of reserves growth for the well is shown by the area between the two lines as illustrated in figure 2-13 graph B.

Another example of technology improvement is captured in graph C. In this case a technology is implemented that reduces the cost of operation and maintenance, thereby extending the reservoir life as shown in figure 2-13 graph C.

Figure 2-13: Impact of Economic and Technology Levers

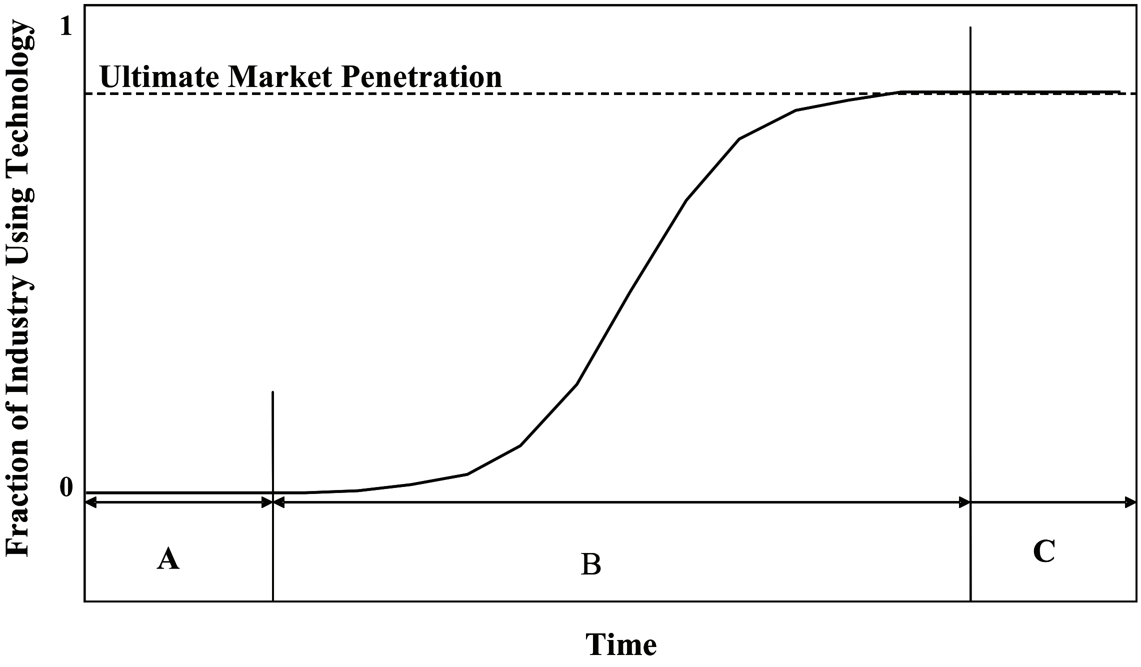


Technology improvements are modeled in OLOGSS using a variety of technology and economic levers. The technology levers, which impact production, are applied to the technical production of the project. The economic levers, which model improvement in project economics, are applied to cashflow calculations. Technology penetration curves are used to model the market penetration of each technology.

The technology-penetration curve is divided into three sections, each of which represents a phase of development. The first section is the research and development phase. In this phase the technology is developed and tested in the laboratory. During these years, the industry may be aware of the technology but has not begun implementation, and therefore does not see a benefit to production or economics. The second section corresponds to the commercialization phase. In the commercialization phase, the technology has successfully left the laboratory and is being adopted by the industry. The third section represents maximum market penetration. This is the ultimate extent to which the technology is adopted by the industry.

Figure 2-14 provides the graph of a generic technology-penetration curve. This graph plots the fraction of industry using the new technology (between 0 and 1) over time. During the research and development phase (A) the fraction of the industry using the technology is 0. This increases during commercialization phase (B) until it reaches the ultimate market penetration. In phase C, the period of maximum market acceptance, the percentage of industry using the technology remains constant.

Figure 2-14: Generic Technology Penetration Curve

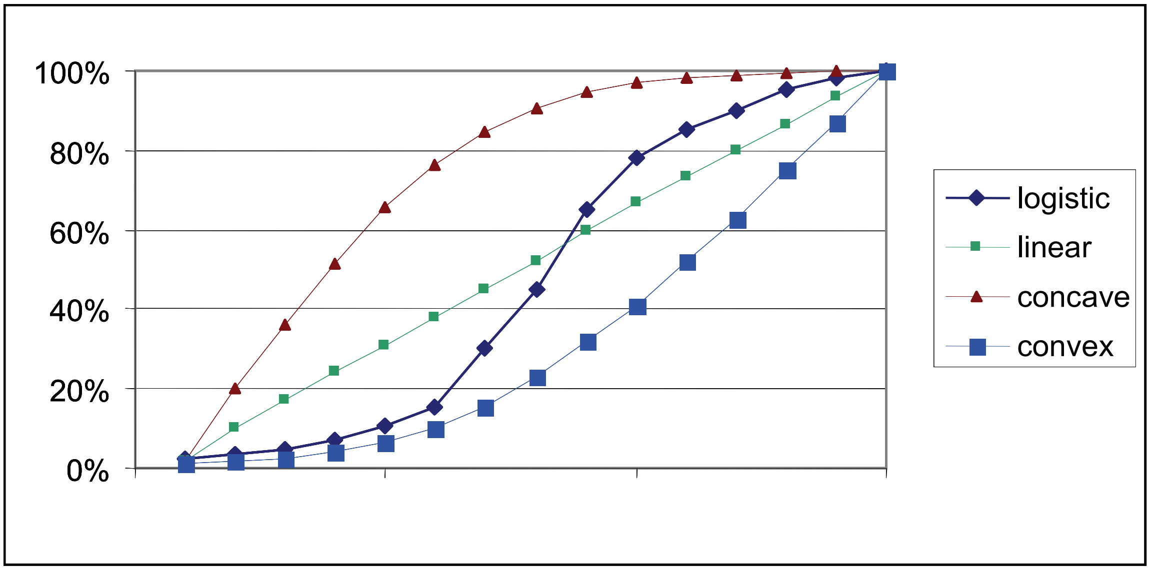


Technology modeling in OLOGSS

The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curve shapes that may represent the adoption of the technology: convex, concave, sigmoid/logistic or linear, as shown in figure 2-15. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The implementation probability does not reflect resource access, development constraints, or economic factors.

Figure 2-15: Potential Market Penetration Profiles



The three phases of the technology penetration curve are modeled using three sets of equations. The first set of equations models the research and development phase, the second set models the commercialization phase, and the third set models the maximum market penetration phase.

In summary, technology penetration curves are defined using the following variables:

- Number of years required to develop a technology = Y_d
- First year of commercialization = Y_c
- Number of years to fully penetrate the market = Y_a
- Ultimate market penetration (%) = UP
- Probability of success = P_s
- Probability of implementation = P_i
- Percent of industry implementing the technology (fraction) in year x = Imp_x

Research and Development Phase:

During the research and development phase, the percentage of industry implementing the new technology for a given year is zero.

This equation is used for all values of *market_penetration_profile.*

Commercialization Phase:

The commercialization phase covers the years from the beginning of commercialization through the number of years required to fully develop the technology. The equations used to model this phase depend upon the value of *market_penetration_profile.*

If the *market_penetration_profile* is assumed to be *convex*, then

Step 1: Calculate raw implementation percentage:

$$\mathrm{Imp}_{xr} = -0.9 * 0.4^{[(x - Ys) / Ya]} \tag{2-105}$$

Step 2: Normalize Imp_x using the following equation:

$$\mathrm{Imp}_x = \frac{[(-0.6523) - \mathrm{Imp}_x]}{[(-0.6523) - (-0.036)]} \tag{2-106}$$

If the *market_penetration_profile* is assumed to be *concave*, then

Step 1: Calculate raw implementation percentage:

$$\mathrm{Imp}_x = 0.9 * 0.04^{[1 - \{(x + 1 - Ys)/ Ya\}]} \tag{2-107}$$

Step 2: Normalize Imp_x using the following equation:

$$\mathrm{Imp}_x = \frac{[(0.04) - \mathrm{Imp}_{xr}]}{[(0.04) - (0.74678)]} \tag{2-108}$$

If the *market_penetration_profile* is assumed to be *sigmoid*, then

Step 1: Determine midpoint of the sigmoid curve = int $\left(\frac{Y_a}{2}\right)$

Where int$\left(\frac{Y_a}{2}\right) = \left(\frac{Y_a}{2}\right)$ rounded to the nearest integer

Step 2: Assign a value of 0 to the midpoint year of the commercialization period, incrementally increase the values for the years above the midpoint year, and incrementally decrease the values for the years below the midpoint year.

Step 3: Calculate raw implementation percentage:

$$\mathrm{Imp}_x = \frac{e^{\mathrm{value}_x}}{1 + e^{\mathrm{value}_x}} \tag{2-109}$$

No normalizing of Imp_x is required for the sigmoid profile.

If the *market_penetration_profile* is assumed to be *linear*, then

Step 1: Calculate the raw implementation percentage:

$$\mathrm{Imp}_x = \left[\frac{P_s * P_i * UP}{Y_a + 1}\right] * x_i \qquad (2\text{-}110)$$

No normalizing of Imp_x is required for the linear profile.

Note that the maximum technology penetration is 1.

Ultimate Market Penetration Phase:
For each of the curves generated, the ultimate technology penetration applied per year will be calculated using:

$$\mathrm{Imp}_{final} = \mathrm{Imp}_x * P_s * P_i \qquad (2\text{-}111)$$

Note that Imp_{final} is not to exceed Ultimate Market Penetration ("UP")

Using these three sets of equations, the industry-wide implementation of a technology improvement can be mapped using a technology-penetration curve.

Levers included in model

Project Level Technology Impact: Adopting a new technology can impact two aspects of a project. It improves the production and/or improves the economics. Technology and economic levers are variables in OLOGSS. The values for these levers are set by the user.

There are two cost variables to which economic levers can be applied in the cashflow calculations: the cost of applying the technology and the cost reductions that result from the technology's implementation. The cost to apply is the incremental cost to apply the technology. The cost reduction is the savings associated with using the new technology. The "cost to apply" levers can be applied at the well and/or project level. The model recognizes the distinction between technologies that are applied at the well level – modeling while drilling - and reservoir characterization and simulation, which affects the entire project. By using both types of levers, users can model the relationship between implementation costs and offsetting cost reductions.

The model assumes that the technology will be implemented only if the cost to apply the technology is less than the increased revenue generated through improved production and cost reductions.

Resource and Filter Levers: Two other types of levers are incorporated into OLOGSS: resource-access levers and technology levers. Resource-access levers allow the user to model changes in resource-access policy. For example, the user can specify that the federal lands in the Santa Maria Basin, which are currently inaccessible due to statutory or executive orders, will be available for exploration in 2015. A series of filter levers is also incorporated in the model. These are used to specifically locate the impact of technology improvement. For example, a technology can be applied only to CO_2 flooding projects in the Rocky Mountain region that are between 5,000 and 7,000 feet deep.

Appendix 2.A: Onshore Lower 48 Data Inventory

Variable Name	Variable Type	Description	Unit
AAPI	Input	API gravity	
AARP	Input	CO_2 source acceptance rate	
ABO	Variable	Current formation volume factor	Bbl/stb
ABOI	Input	Initial formation volume factor	Bbl/stb
ABTU	Variable	BTU content	Btu/Cf
ACER	Input	ACE rate	Percent
ACHGASPROD	Input	Cumulative historical natural gas production	MMcf
ACHOILPROD	Input	Cumulative historical crude oil production	MBbl
ACO2CONT	Input	CO_2 impurity content	%
ADEPTH	Input	Depth	Feet
ADGGLA	Variable	Depletable items in the year (G & G and lease acquisition cost)	K$
ADJGAS	Variable	National natural gas drilling adjustment factor	Fraction
ADJGROSS	Variable	Adjusted gross revenue	K$
ADJOIL	Variable	National crude oil drilling adjustment factor	Fraction
ADOILPRICE	Variable	Adjusted crude oil price	$/Bbl
ADVANCED	Variable	Patterns to be developed using advanced technology	Fraction
AECON_LIFE	Variable	Economic life of the project	Years
AFLP	Input	Portion of reservoir on federal lands	Fraction
AGAS_GRAV	Input	Natural gas gravity	
AGOR	Input	Gas/oil ratio	Mcf/bbl
AH2SCONT	Input	H_2S impurity content	%
AHCPV	Variable	Hydro Carbon Pore Volume	0.4 HCPV
AHEATVAL	Input	Heat content of natural gas	Btu/Cf
AINJINJ	Input	Annual injectant injected	MBbl, Mcf, MLbs
AINJRECY	Variable	Annual injectant recycled	MBbl, Mcf
AIRSVGAS	Variable	End of year inferred natural gas reserves	MMcf
AIRSVOIL	Variable	End of year inferred crude oil reserves	MBbl
ALATLEN	Input	Lateral length	Feet
ALATNUM	Input	Number of laterals	
ALYRGAS	Input	Last year of historical natural gas production	MMcf

ALYROIL	Input	Last year of historical crude oil production	MBbl
AMINT	Variable	Alternative minimum income tax	K$
AMOR	Variable	Intangible investment depreciation amount	K$
AMOR_BASE	Variable	Amortization base	K$
AMORSCHL	Input	Annual fraction amortized	Fraction
AMT	Input	Alternative minimum tax	K$
AMTRATE	Input	Alternative minimum tax rate	K$
AN2CONT	Input	N_2 impurity content	%
ANGL	Input	NGL	bbl/MMcf
ANUMACC	Input	Number of accumulations	
ANWELLGAS	Input	Number of natural gas wells	
ANWELLINJ	Input	Number of injection wells	
ANWELLOIL	Input	Number of crude oil wells	
AOAM	Variable	Annual fixed O & M cost	K$
AOGIP	Variable	Original Gas in Place	Bcf
AOILVIS	Input	Crude Oil viscosity	CP
AOOIP	Variable	Original Oil In Place	MBbl
AORGOOIP	Input	Original OOIP	MBbl
APATSIZ	Input	Pattern size	Acres
APAY	Input	Net pay	Feet
APD	Variable	Annual percent depletion	K$
APERM	Input	Permeability	MD
APHI	Input	Porosity	Percent
APLAY_CDE	Input	Play number	
APRESIN	Variable	Initial pressure	PSIA
APRODCO2	Input	Annual CO_2 production	MMcf
APRODGAS	Input	Annual natural gas production	MMcf
APRODNGL	Input	Annual NGL production	MBbl
APRODOIL	Input	Annual crude oil production	MBbl
APRODWAT	Input	Annual water production	MBbl
APROV	Input	Province	
AREGION	Input	Region number	
ARESACC	Input	Resource Access	
ARESFLAG	Input	Resource flag	
ARESID	Input	Reservoir ID number	
ARESVGAS	Variable	End of year proven natural gas reserves	MMcf
ARESVOIL	Variable	End of year proven crude oil reserves	MBbl
ARRC	Input	Railroad Commission District	
ASC	Input	Reservoir Size Class	
ASGI	Variable	Gas saturation	Percent
ASOC	Input	Current oil saturation	Percent
ASOI	Input	Initial oil saturation	Percent

ASOR	Input	Residual oil saturation	Percent
ASR_ED	Input	Number of years after economic life of ASR	
ASR_ST	Input	Number of years before economic life of ASR	
ASULFOIL	Input	Sulfur content of crude oil	%
ASWI	Input	Initial water saturation	Percent
ATCF	Variable	After tax cashflow	K$
ATEMP	Variable	Reservoir temperature	F°
ATOTACRES	Input	Total area	Acres
ATOTCONV	Input	Number of conversions from producing wells to injecting wells per pattern	
ATOTINJ	Input	Number of new injectors drilled per pattern	
ATOTPAT	Input	Total number of patterns	
ATOTPROD	Input	Number of new producers drilled per pattern	
ATOTPS	Input	Number of primary wells converted to secondary wells per pattern	
AVDP	Input	Dykstra Parsons coefficient	
AWATINJ	Input	Annual water injected	MBbl
AWOR	Input	Water/oil ratio	Bbl/Bbl
BAS_PLAY	Input	Basin number	
BASEGAS	Input	Base natural gas price used for normalization of capital and operating costs	$/Mcf
BASEOIL	Input	Base crude oil price used for normalization of capital and operating costs	K$
BSE_AVAILCO2	Variable	Base annual volume of CO_2 available by region	Bcf
CAP_BASE	Variable	Capital to be depreciated	K$
CAPMUL	Input	Capital constraints multiplier	
CATCF	Variable	Cumulative discounted cashflow	K$
CHG_ANNSEC_FAC	Input	Change in annual secondary operating cost	Fraction
CHG_CHMPNT_FAC	Input	Change in chemical handling plant cost	Fraction
CHG_CMP_FAC	Input	Change in compression cost	Fraction
CHG_CO2PNT_FAC	Input	Change in CO_2 injection/recycling plant cost	Fraction
CHG_COMP_FAC	Input	Change in completion cost	Fraction
CHG_DRL_FAC	Input	Change in drilling cost	Fraction
CHG_FAC_FAC	Input	Change in facilities cost	Fraction

CHG_FACUPG_FAC	Input	Change in facilities upgrade cost	Fraction
CHG_FOAM_FAC	Input	Change in fixed annual O & M cost	Fraction
CHG_GNA_FAC	Input	Change in G & A cost	Fraction
CHG_INJC_FAC	Input	Change in injection cost	Fraction
CHG_INJCONV_FAC	Input	Change in injector conversion cost	Fraction
CHG_INJT_FAC	Input	Change in injectant cost	Fraction
CHG_LFT_FAC	Input	Change in lifting cost	Fraction
CHG_OGAS_FAC	Input	Change in natural gas O & M cost	K$
CHG_OINJ_FAC	Input	Change in injection O & M cost	K$
CHG_OOIL_FAC	Input	Change in oil O & M cost	K$
CHG_OWAT_FAC	Input	Change in water O & M cost	K$
CHG_PLYPNT_FAC	Input	Change in polymer handling plant cost	Fraction
CHG_PRDWAT_FAC	Input	Change in produced water handling plant cost	Fraction
CHG_SECWRK_FAC	Input	Change in secondary workover cost	Fraction
CHG_SECCONV_FAC	Input	Change in secondary conversion cost	Fraction
CHG_STM_FAC	Input	Change in stimulation cost	Fraction
CHG_STMGEN_FAC	Input	Change in steam generation and distribution cost	Fraction
CHG_VOAM_FAC	Input	Change in variable O & M cost	Fraction
.CHG_WRK_FAC	Input	Change in workover cost	Fraction
CHM_F	Variable	Cost for a chemical handling plant	K$
CHMA	Input	Chemical handling plant	
CHMB	Input	Chemical handling plant	
CHMK	Input	Chemical handling plant	
CIDC	Input	Capitalize intangible drilling costs	K$
CO2_F	Variable	Cost for a CO_2 recycling/injection plant	K$
CO2_RAT_ FAC	Input	CO_2 injection factor	
CO2AVAIL	Variable	Total CO_2 available in a region across all sources	Bcf/Yr
CO2BASE	Input	Total Volume of CO_2 Available	Bcf/Yr
CO2COST	Variable	Final cost for CO_2	$/Mcf

CO2B	Input	Constant and coefficient for natural CO_2 cost equation	
CO2K	Input	Constant and coefficient for natural CO_2 cost equation	
CO2MUL	Input	CO_2 availability constraint multiplier	
CO2OAM	Variable	CO_2 variable O & M cost	K$
CO2OM_20	Input	The O & M cost for CO_2 injection < 20 MMcf	K$
CO2OM20	Input	The O & M cost for CO_2 injection > 20 MMcf	K$
CO2PR	Input	State/regional multipliers for natural CO_2 cost	
CO2PRICE	Input	CO_2 price	$/Mcf
CO2RK, CO2RB	Input	CO_2 recycling plant cost	K$
CO2ST	Input	State code for natural CO_2 cost	
COI	Input	Capitalize other intangibles	
COMP	Variable	Compressor cost	K$
COMP_OAM	Variable	Compressor O & M cost	K$
COMP_VC	Input	Compressor O & M costs	K$
COMP_W	Variable	Compression cost to bring natural gas up to pipeline pressure	K$
COMYEAR_FAC	Input	Number of years of technology commercialization for the penetration curve	Years
CONTIN_ FAC	Input	Continuity increase factor	
COST_BHP	Input	Compressor Cost	$/Bhp
COTYPE	Variable	CO_2 source, either industrial or natural	
CPI_2003	Variable	CPI conversion for 2003$	
CPI_2005	Variable	CPI conversion for 2005$	
CPI_AVG	Input	Average CPI from 1990 to 2010	
CPI_FACTOR	Input	CPI factor from 1990 to 2010	
CPI_YEAR	Input	Year for CPI index	
CREDAMT	Input	Flag that allows AMT to be credited in future years	
CREGPR	Input	The CO_2 price by region and source	$/Mcf
CST_ANNSEC_ FAC	Input	Well level cost to apply secondary producer technology	K$
CST_ANNSEC_CSTP	Variable	Project level cost to apply secondary producer technology	K$

CST_CMP_CSTP	Variable	Project level cost to apply compression technology	K$
CST_CMP_FAC	Input	Well level cost to apply compression technology	K$
CST_COMP_ FAC	Input	Well level cost to apply completion technology	K$
CST_COMP_CSTP	Variable	Project level cost to apply completion technology	K$
CST_DRL_ FAC	Input	Well level cost to apply drilling technology	K$
CST_DRL_CSTP	Variable	Project level cost to apply drilling technology	K$
CST_FAC_ FAC	Input	Well level cost to apply facilities technology	K$
CST_FAC_CSTP	Variable	Project level cost to apply facilities technology	K$
CST_FACUPG_ FAC	Input	Well level cost to apply facilities upgrade technology	K$
CST_FACUPG_CSTP	Variable	Project level cost to apply facilities upgrade technology	K$
CST_FOAM_ FAC	Input	Well level cost to apply fixed annual O & M technology	K$
CST_FOAM_CSTP	Variable	Project level cost to apply fixed annual O & M technology	K$
CST_GNA_ FAC	Input	Well level cost to apply G & A technology	K$
CST_GNA_CSTP	Variable	Project level cost to apply G & A technology	K$
CST_INJC_ FAC	Input	Well level cost to apply injection technology	K$
CST_INJC_CSTP	Variable	Project level cost to apply injection technology	K$
CST_INJCONV_ FAC	Input	Well level cost to apply injector conversion technology	K$
CST_INJCONV_CSTP	Variable	Project level cost to apply injector conversion technology	K$
CST_LFT_ FAC	Input	Well level cost to apply lifting technology	K$
CST_LFT_CSTP	Variable	Project level cost to apply lifting technology	K$
CST_SECCONV_ FAC	Input	Well level cost to apply secondary conversion technology	K$

CST_SECCONV_CSTP	Variable	Project level cost to apply secondary conversion technology	K$
CST_SECWRK_ FAC	Input	Well level cost to apply secondary workover technology	K$
CST_SECWRK_CSTP	Variable	Project level cost to apply secondary workover technology	K$
CST_STM_ FAC	Input	Well level cost to apply stimulation technology	K$
CST_STM_CSTP	Variable	Project level cost to apply stimulation technology	K$
CST_VOAM_ FAC	Input	Well level cost to apply variable annual O & M technology	K$
CST_VOAM_CSTP	Variable	Project level cost to apply variable annual O & M technology	K$
CST_WRK_ FAC	Input	Well level cost to apply workover technology	K$
CST_WRK_CSTP	Variable	Project level cost to apply workover technology	K$
CSTP_ANNSEC_ FAC	Input	Project level cost to apply secondary producer technology	K$
CSTP_CMP_ FAC	Input	Project level cost to apply compression technology	K$
CSTP_COMP_ FAC	Input	Project level cost to apply completion technology	K$
CSTP_DRL_ FAC	Input	Project level cost to apply drilling technology	K$
CSTP_FAC_ FAC	Input	Project level cost to apply facilities technology	K$
CSTP_FACUPG_ FAC	Input	Project level cost to apply facilities upgrade technology	K$
CSTP_FOAM_ FAC	Input	Project level cost to apply fixed annual O & M technology	K$
CSTP_GNA_ FAC	Input	Project level cost to apply G & A technology	K$
CSTP_INJC_ FAC	Input	Project level cost to apply injection technology	K$
CSTP_INJCONV_ FAC	Input	Project level cost to apply injector conversion technology	K$
CSTP_LFT_ FAC	Input	Project level cost to apply lifting technology	K$

CSTP_SECCONV_ FAC	Input	Project level cost to apply secondary conversion technology	K$
CSTP_SECWRK_ FAC	Input	Project level cost to apply secondary workover technology	K$
CSTP_STM_ FAC	Input	Project level cost to apply stimulation technology	K$
CSTP_VOAM_ FAC	Input	Project level cost to apply variable annual O & M technology	K$
CSTP_WRK_ FAC	Input	Project level cost to apply workover technology	K$
CUTOIL	Input	Base crude oil price for the adjustment term of price normalization	$/Bbl
DATCF	Variable	Discounted cashflow after taxes	K$
DEP_CRD	Variable	Depletion credit	K$
DEPLET	Variable	Depletion allowance	K$
DEPR	Variable	Depreciation amount	K$
DEPR_OVR	Input	Annual fraction to depreciate	
DEPR_PROC	Input	Process number for override schedule	
DEPR_YR	Input	Number of years for override schedule	
DEPRSCHL	Input	Annual Fraction Depreciated	Fraction
DEPR_SCH	Variable	Process specific depreciation schedule	Years
DGGLA	Variable	Depletion base (G & G and lease acquisition cost)	K$
DISC_DRL	Variable	Discounted drilling cost	K$
DISC_FED	Variable	Discounted federal tax payments	K$
DISC_GAS	Variable	Discounted revenue from natural gas sales	K$
DISC_INV	Variable	Discounted investment rate	K$
DISC_NDRL	Variable	Discounted project facilities costs	K$
DISC_OAM	Variable	Discounted O & M cost	K$
DISC_OIL	Variable	Discounted revenue from crude oil sales	K$
DISC_ROY	Variable	Discounted royalty	K$
DISC_ST	Variable	Discounted state tax rate	K$
DISCLAG	Input	Number of years between discovery and first production	
DISCOUNT_RT	Input	Process discount rates	Percent

DRCAP_D	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
DRCAP_G	Variable	Regional natural gas well drilling footage constraints	Ft
DRCAP_O	Variable	Regional crude oil well drilling footage constraints	Ft
DRILL_FAC	Input	Drilling rate factor	
DRILL_OVER	Input	Drilling constraints available for footage over run	%
DRILL_RES	Input	Development drilling constraints available for transfer between crude oil and natural gas	%
DRILL_TRANS	Input	Drilling constraints transfer between regions	%
DRILLCST	Variable	Drill cost by project	K$
DRILLL48	Variable	Successful well drilling costs	1987$ per well
DRL_CST	Variable	Drilling cost	K$
DRY_CST	Variable	Dryhole drilling cost	K$
DRY_DWCA	Estimated	Dryhole well cost	K$
DRY_DWCB	Estimated	Dryhole well cost	K$
DRY_DWCC	Estimated	Dryhole well cost	K$
DRY_DWCD	Input	Maximum depth range for dry well drilling cost equations	Ft
DRY_DWCK	Estimated	Constant for dryhole drilling cost equation	
DRY_DWCM	Input	Minimum depth range for dry well drilling equations	Ft
DRY_W	Variable	Cost to drill a dry well	K$
DRYCST	Variable	Dryhole cost by project	K$
DRYL48	Variable	Dry well drilling costs	1987$ per well
DRYWELLL48	Variable	Dry Lower 48 onshore wells drilled	Wells
DWC_W	Variable	Cost to drill and complete a crude oil well	K$
EADGGLA	Variable	G&G and lease acquisition cost depletion	K$
EADJGROSS	Variable	Adjusted revenue	K$
EAMINT	Variable	Alternative minimum tax	K$
EAMOR	Variable	Amortization	K$
EAOAM	Variable	Fixed annual operating cost	K$
EATCF	Variable	After tax cash flow	K$
ECAP_BASE	Variable	Depreciable/capitalized base	K$

ECATCF	Variable	Cumulative discounted after tax cashflow	K$
ECO2CODE	Variable	CO_2 source code	
ECO2COST	Variable	CO_2 cost	K$
ECO2INJ	Variable	Economic CO_2 injection	Bcf/Yr
ECO2LIM	Variable	Source specific project life for CO_2 EOR projects	
ECO2POL	Variable	Injected CO_2	MMcf
ECO2RANKVAL	Variable	Source specific ranking value for CO_2 EOR projects	
ECO2RCY	Variable	CO_2 recycled	Bcf/Yr
ECOMP	Variable	Compressor tangible capital	K$
EDATCF	Variable	Discounted after tax cashflow	K$
EDEP_CRD	Variable	Adjustment to depreciation base for federal tax credits	K$
EDEPGGLA	Variable	Depletable G & G/lease cost	K$
EDEPLET	Variable	Depletion	K$
EDEPR	Variable	Depreciation	K$
EDGGLA	Variable	Depletion base	K$
EDRYHOLE	Variable	Number of dryholes drilled	
EEC	Input	Expensed environmental costs	K$
EEGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EEORTCA	Variable	Tax credit addback	K$
EEXIST_ECAP	Variable	Environmental existing capital	K$
EEXIST_EOAM	Variable	Environmental existing O & M costs	K$
EFEDCR	Variable	Federal tax credits	K$
EFEDROY	Variable	Federal royalty	K$
EFEDTAX	Variable	Federal tax	K$
EFOAM	Variable	CO_2 FOAM cost	K$
EGACAP	Variable	G & A capitalized	K$
EGAEXP	Variable	G & A expensed	K$
EGASPRICE2	Variable	Natural gas price used in the economics	K$
EGG	Variable	Expensed G & G cost	K$
EGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EGGLAADD	Variable	G & G/lease addback	K$
EGRAVADJ	Variable	Gravity adjustment	K$
EGREMRES	Variable	Remaining proven natural gas reserves	Bcf
EGROSSREV	Variable	Gross revenues	K$
EIA	Variable	Environmental intangible addback	K$

EICAP	Variable	Environmental intangible capital	
EICAP2	Variable	Environmental intangible capital	
EIGEN	Variable	Number of steam generators	
EIGREMRES	Variable	Remaining inferred natural gas reserves	Bcf
EII	Variable	Intangible investment	K$
EIIDRL	Variable	Intangible investment drilling	K$
EINJCOST	Variable	CO_2/Polymer cost	K$
EINJDR	Variable	New injection wells drilled per year	
EINJWELL	Variable	Active injection wells per year	
EINTADD	Variable	Intangible addback	K$
EINTCAP	Variable	Tangible investment drilling	K$
EINVEFF	Variable	Investment efficiency	
EIREMRES	Variable	Remaining inferred crude oil reserves	MMBbl
EITC	Input	Environmental intangible tax credit	K$
EITCAB	Input	Environmental intangible tax credit rate addback	%
EITCR	Input	Environmental intangible tax credit rate	K$
ELA	Variable	Lease and acquisition cost	K$
ELYRGAS	Variable	Last year of historical natural gas production	MMcf
ELYROIL	Variable	Last year of historical crude oil production	MBbl
ENETREV	Variable	Net revenues	K$
ENEW_ECAP	Variable	Environmental new capital	K$
ENEW_EOAM	Variable	Environmental new O & M costs	K$
ENIAT	Variable	Net income after taxes	K$
ENIBT	Variable	Net income before taxes	K$
ENPV	Variable	Net present value	K$
ENV_FAC	Input	Environmental capital cost multiplier	
ENVOP_FAC	Input	Environmental operating cost multiplier	
ENVSCN	Input	Include environmental costs?	
ENYRSI	Variable	Number of years project is economic	
EOAM	Variable	Variable operating and maintenance	K$

EOCA	Variable	Environmental operating cost addback	K$
EOCTC	Input	Environmental operating cost tax credit	K$
EOCTCAB	Input	Environmental operating cost tax credit rate addback	%
EOCTCR	Input	Environmental operating cost tax credit rate	K$
EOILPRICE2	Variable	Crude oil price used in the economics	K$
EORTC	Input	EOR tax credit	K$
EORTCA	Variable	EOR tax credit addback	K$
EORTCAB	Input	EOR tax credit rate addback	%
EORTCP	Input	EOR tax credit phase out crude oil price	K$
EORTCR	Input	EOR tax credit rate	K$
EORTCRP	Input	EOR tax credit applied by year	%
EOTC	Variable	Other tangible capital	K$
EPROC_OAM	Variable	Natural gas processing cost	K$
EPRODDR	Variable	New production wells drilled per year	
EPRODGAS	Variable	Economic natural gas production	MMcf
EPRODOIL	Variable	Economic crude oil production	MBbl
EPRODWAT	Variable	Economic water production	MBbl
EPRODWELL	Variable	Active producing wells per year	
EREMRES	Variable	Remaining proven crude oil reserves	MMBbl
EROR	Variable	Rate of return	
EROY	Variable	Royalty	K$
ESEV	Variable	Severance tax	K$
ESHUTIN	Variable	New shut in wells drilled per year	
ESTIM	Variable	Stimulation cost	K$
ESTTAX	Variable	State tax	K$
ESUMP	Variable	Number of patterns	
ESURFVOL	Variable	Total volume injected	MMcf/ MBbl/ MLbs
ETAXINC	Variable	Net income before taxes	K$
ETCADD	Variable	Tax credit addbacks taken from NIAT	K$
ETCI	Variable	Federal tax credit	K$
ETCIADJ	Variable	Adjustment for federal tax credit	K$

ETI	Variable	Tangible investments	K$
ETOC	Variable	Total operating cost	K$
ETORECY	Variable	CO_2/Surf/Steam recycling volume	Bcf/MBbl/Yr
ETORECY_CST	Variable	CO_2/Surf/Steam recycling cost	Bcf/MBbl/Yr
ETTC	Input	Environmental tangible tax credit	K$
ETTCAB	Input	Environmental tangible tax credit rate addback	%
ETTCR	Input	Environmental tangible tax credit rate	K$
EWATINJ	Variable	Economic water injected	MBbl
EX_CONRES	Variable	Number of exploration reservoirs	
EX_FCRES	Variable	First exploration reservoir	
EXIST_ECAP	Variable	Existing environmental capital cost	K$
EXIST_EOAM	Variable	Existing environmental O & M cost	K$
EXP_ADJ	Input	Fraction of annual crude oil exploration drilling which is made available	Fraction
EXP_ADJG	Input	Fraction of annual natural gas exploration drilling which is made available	Fraction
EXPA0	Estimated	Crude oil exploration well footage A0	
EXPA1	Estimated	Crude oil exploration well footage A1	
EXPAG0	Input	Natural gas exploration well footage A0	
EXPAG1	Input	Natural gas exploration well footage A1	
EXPATN	Variable	Number of active patterns	
EXPCDRCAP	Variable	Regional conventional exploratory drilling footage constraints	Ft
EXPCDRCAPG	Variable	Regional conventional natural gas exploration drilling footage constraint	Ft
EXPGG	Variable	Expensed G & G cost	K$
EXPL_FRAC	Input	Exploration drilling for conventional crude oil	%
EXPL_FRACG	Input	Exploration drilling for conventional natural gas	%

EXPL_MODEL	Input	Selection of exploration models	
EXPLA	Variable	Expensed lease purchase costs	K$
EXPLR_ FAC	Input	Exploration factor	
EXPLR_CHG	Variable	Change in exploration rate	
EXPLSORTIRES	Variable	Sort pointer for exploration	
EXPMUL	Input	Exploration constraint multiplier	
EXPRDL48	Variable	Expected Production	Oil-MMB Gas-BCF
EXPUDRCAP	Variable	Regional continuous exploratory drilling footage constraints	Ft
EXPUDRCAPG	Variable	Regional continuous natural gas exploratory drilling footage constraints	Ft
FAC_W	Variable	Facilities upgrade cost	K$
FACCOST	Variable	Facilities cost	K$
FACGA	Estimated	Natural gas facilities costs	
FACGB	Estimated	Natural gas facilities costs	
FACGC	Estimated	Natural gas facilities costs	
FACGD	Input	Maximum depth range for natural gas facilities costs	Ft
FACGK	Estimated	Constant for natural gas facilities costs	
FACGM	Input	Minimum depth range for natural gas facilities costs	Ft
FACUPA	Estimated	Facilities upgrade cost	
FACUPB	Estimated	Facilities upgrade cost	
FACUPC	Estimated	Facilities upgrade cost	
FACUPD	Input	Maximum depth range for facilities upgrade cost	Ft
FACUPK	Estimated	Constant for facilities upgrade costs	
FACUPM	Input	Minimum depth range for facilities upgrade cost	Ft
FCO2	Variable	Cost multiplier for natural CO_2	
FEDRATE	Input	Federal income tax rate	Percent
FEDTAX	Variable	Federal tax	K$
FEDTAX_CR	Variable	Federal tax credits	K$
FIRST_ASR	Variable	First year a decline reservoir will be considered for ASR	
FIRST_DEC	Variable	First year a decline reservoir will be considered for EOR	

FIRSTCOM_FAC	Input	First year of commercialization for technology on the penetration curve	
FIT	Variable	Federal income tax	K$
FOAM	Variable	CO_2 fixed O & M cost	K$
FOAMG_1	Variable	Fixed annual operating cost for natural gas 1	K$
FOAMG_2	Variable	Fixed annual operating cost for natural gas 2	K$
FOAMG_W	Variable	Fixed operating cost for natural gas wells	K$
FGASPRICE	Input	Fixed natural gas price	$/MCF
FOILPRICE	Input	Fixed crude oil price	$/BBL
FPLY	Variable	Cost multiplier for polymer	
FPRICE	Input	Selection to use fixed prices	
FR1L48	Variable	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well
FR2L48	Variable	Finding rates for other exploratory drilling	Oil-MMB per well Gas-BCF per well
FR3L48	Variable	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well
FRAC_CO2	Variable	Fraction of CO_2	Fraction
FRAC_H2S	Variable	Fraction of hydrogen sulfide	Fraction
FRAC_N2	Variable	Fraction of nitrogen	Fraction
FRAC_NGL	Variable	NGL yield	Fraction
FWC_W	Variable	Natural gas facilities costs	K$
GA_CAP	Variable	G & A on capital	K$
GA_EXP	Variable	G & A on expenses	K$
GAS_ADJ	Input	Fraction of annual natural gas drilling which is made available	Fraction
GAS_CASE	Input	Filter for all natural gas processes	
GAS_DWCA	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCB	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCC	Estimated	Horizontal natural gas drilling and completion costs	

GAS_DWCD	Input	Maximum depth range for natural gas well drilling cost equations	Ft
GAS_DWCK	Estimated	Constant for natural gas well drilling cost equations	
GAS_DWCM	Input	Minimum depth range for natural gas well drilling cost equations	Ft
GAS_FILTER	Input	Filter for all natural gas processes	
GAS_OAM	Input	Process specific operating cost for natural gas production	$/Mcf
GAS_SALES	Input	Will produced natural gas be sold?	
GASA0	Estimated	Natural gas footage A0	
GASA1	Estimated	Natural gas footage A1	
GASD0	Input	Natural gas drywell footage A0	
GASD1	Input	Natural gas drywell footage A1	
GASPRICE2	Variable	Natural gas price dummy to shift price track	K$
GASPRICEC	Variable	Annual natural gas prices used by cashflow	K$
GASPRICED	Variable	Annual natural gas prices used in the drilling constraints	K$
GASPRICEO	Variable	Annual natural gas prices used by the model	K$
GASPROD	Variable	Annual natural gas production	MMcf
GG	Variable	G & G cost	K$
GG_FAC	Input	G & G factor	
GGCTC	Input	G & G tangible depleted tax credit	K$
GGCTCAB	Input	G & G tangible tax credit rate addback	%
GGCTCR	Input	G & G tangible depleted tax credit rate	K$
GGETC	Input	G & G intangible depleted tax credit	K$
GGETCAB	Input	G & G intangible tax credit rate addback	%
GGETCR	Input	G & G intangible depleted tax credit rate	K$
GGLA	Variable	G & G and lease acquisition addback	K$
GMULT_INT	Input	Natural gas price adjustment factor, intangible costs	K$

GMULT_OAM	Input	Natural gas price adjustment factor, O & M	K$
GMULT_TANG	Input	Natural gas price adjustment factor, tangible costs	K$
GNA_CAP2	Input	G & A capital multiplier	Fraction
GNA_EXP2	Input	G & A expense multiplier	Fraction
GPROD	Variable	Well level natural gas production	MMcf
GRAVPEN	Variable	Gravity penalty	K$
GREMRES	Variable	Remaining proven natural gas reserves	MMcf
GROSS_REV	Variable	Gross revenue	K$
H_GROWTH	Input	Horizontal growth rate	Percent
H_PERCENT	Input	Crude oil constraint available for horizontal drilling	%
H_SUCCESS	Input	Horizontal development well success rate by region	%
H2SPRICE	Input	H_2S price	$/Metric ton
HOR_ADJ	Input	Fraction of annual horizontal drilling which is made available	Fraction
HOR_VERT	Input	Split between horizontal and vertical drilling	
HORMUL	Input	Horizontal drilling constraint multiplier	
IAMORYR	Input	Number of years in default amortization schedule	
ICAP	Variable	Other intangible costs	K$
ICST	Variable	Intangible cost	K$
IDCA	Variable	Intangible drilling capital addback	K$
IDCTC	Input	Intangible drilling cost tax credit	K$
IDCTCAB	Input	Intangible drilling cost tax credit rate addback	%
IDCTCR	Input	Intangible drilling cost tax credit rate	K$
IDEPRYR	Input	Number of years in default depreciation schedule	
IGREMRES	Variable	Remaining inferred natural gas reserves	MMcf
II_DRL	Variable	Intangible drilling cost	K$
IINFARSV	Variable	Initial inferred AD gas reserves	Bcf
IINFRESV	Variable	Initial inferred reserves	MMBbl
IMP_CAPCR	Input	Capacity for NGL cryogenic expander plant	MMCf/D

IMP_CAPST	Input	Capacity for NGL straight refrigeration	MMCf/D
IMP_CAPSU	Input	Capacity for Claus Sulfur Recovery	Long ton/day
IMP_CAPTE	Input	Natural gas processing plant capacity	MMcf/D
IMP_CO2_LIM	Input	Limit on CO_2 in natural gas	Fraction
IMP_DIS_RATE	Input	Discount rate for natural gas processing plant	
IMP_H2O_LIM	Input	Limit on H_2O in natural gas	Fraction
IMP_H2S_LIM	Input	Limit on H_2S in natural gas	Fraction
IMP_N2_LIM	Input	Limit on N^2 in natural gas	Fraction
IMP_NGL_LIM	Input	Limit on NGL in natural gas	Fraction
IMP_OP_FAC	Input	Natural gas processing operating factor	
IMP_PLT_LFE	Input	Natural gas processing plant life	Years
IMP_THRU	Input	Throughput	
IND_SRCCO2	Input	Use industrial source of CO_2?	
INDUSTRIAL	Variable	Natural or industrial CO_2 source	
INFLFAC	Input	Annual Inflation Factor	
INFR_ADG	Input	Adjustment factor for inferred AD gas reserves	Tcf
INFR_CBM	Input	Adjustment factor for inferred coalbed methane reserves	Tcf
INFR_DNAG	Input	Adjustment factor for inferred deep non-associated gas reserves	Tcf
INFR_OIL	Input	Adjustment factor for inferred crude oil reserves	Bbl?
INFR_SHL	Input	Adjustment factor for inferred shale gas reserves	Tcf
INFR_SNAG	Input	Adjustment factor for inferred shallow non-associated gas reserves	Tcf
INFR_THT	Input	Adjustment factor for inferred tight gas reserves	Tcf
INFARSV	Variable	Inferred AD gas reserves	Bcf
INFRESV	Variable	Inferred reserves, crude oil or natural gas	MMBbl, Bcf
INJ	Variable	Injectant cost	K$
INJ_OAM	Input	Process specific operating cost for injection	$/Bbl
INJ_RATE_FAC	Input	Injection rate increase	fraction
INTADD	Variable	Total intangible addback	K$
INTANG_M	Variable	Intangible cost multiplier	

INTCAP	Variable	Intangible to be capitalized	K$
INVCAP	Variable	Annual total capital investments constraints, used for constraining projects	MM$
IPDR	Input	Independent producer depletion rate	
IRA	Input	Max alternate minimum tax reduction for independents	K$
IREMRES	Variable	Remaining inferred crude oil reserves	MBbl
IUNDARES	Variable	Initial undiscovered resource	MMBbl/Tcf
IUNDRES	Variable	Initial undiscovered resource	MMBbl/Tcf
L48B4YR	Input	First year of analysis	
LA	Variable	Lease and acquisition cost	K$
LACTC	Input	Lease acquisition tangible depleted tax credit	K$
LACTCAB	Input	Lease acquisition tangible credit rate addback	%
LACTCR	Input	Lease acquisition tangible depleted tax credit rate	K$
LAETC	Input	Lease acquisition intangible expensed tax credit	K$
LAETCAB	Input	Lease acquisition intangible tax credit rate addback	%
LAETCR	Input	Lease acquisition intangible expensed tax credit rate	K$
LAST_ASR	Variable	Last year a decline reservoir will be considered for ASR	
LAST_DEC	Variable	Last year a decline reservoir will be considered for EOR	
LBC_FRAC	Input	Lease bonus fraction	Fraction
LEASCST	Variable	Lease cost by project	K$
LEASL48	Variable	Lease equipment costs	1987$/well
MARK_PEN_FAC	Input	Ultimate market penetration	
MAXWELL	Input	Maximum number of dryholes per play per year	
MAX_API_CASE	Input	Maximum API gravity	
MAX_DEPTH_CASE	Input	Maximum depth	
MAX_PERM_CASE	Input	Maximum permeability	
MAX_RATE_CASE	Input	Maximum production rate	
MIN_API_CASE	Input	Minimum API gravity	
MIN_DEPTH_CASE	Input	Minimum depth	
MIN_PERM_CASE	Input	Minimum permeability	
MIN_RATE_CASE	Input	Minimum production rate	
MOB_RAT_ FAC	Input	Change in mobility ratio	
MPRD	Input	Maximum depth range for new producer equations	Ft

N_CPI	Input	Number of years	
N2PRICE	Input	N_2 price	$/Mcf
NAT_AVAILCO2	Input	Annual CO_2 availability by region	Bcf
NAT_DMDGAS	Variable	Annual natural gas demand in region	Bcf/Yr
NAT_DRCAP_D	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_DRCAP_G	Variable	National natural gas well drilling footage constraints	Ft
NAT_DRCAP_O	Variable	National crude oil well drilling footage constraints	Ft
NAT_DUAL	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_EXP	Variable	National exploratory drilling constraint	Bcf/Yr
NAT_EXPC	Variable	National conventional exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPCDRCAP	Variable	National conventional exploratory drilling footage constraints	Ft
NAT_EXPCDRCAPG	Variable	National high-permeability natural gas exploratory drilling footage constraints	Ft
NAT_EXPCG	Variable	National conventional exploratory drilling natural gas constraint	Bcf/Yr
NAT_EXPG	Variable	National natural gas exploration drilling constraint	Bcf/Yr
NAT_EXPU	Variable	National continuous exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPUDRCAP	Variable	National continuous exploratory drilling footage constraints	Ft
NAT_EXPUDRCAPG	Variable	National continuous natural gas exploratory drilling footage constraints	Ft
NAT_EXPUG	Variable	National continuous exploratory drilling natural gas constraint	Bcf/Yr
NAT_GAS	Variable	National natural gas drilling constraint	Bcf/Yr
NAT_GDR	Variable	National natural gas dry drilling footage	Bcf/Yr

NAT_HGAS	Variable	Annual dry natural gas	MMcf
NAT_HOIL	Variable	Annual crude oil and lease condensates	MBbl
NAT_HOR	Variable	Horizontal drilling constraint	MBbl/Yr
NAT_INVCAP	Input	Annual total capital investment constraint	MM$
NAT_ODR	Variable	National crude oil dry drilling footage	MBbl/Yr
NAT_OIL	Variable	National crude oil drilling constraint	MBbl/Yr
NAT_SRCCO2	Input	Use natural source of CO_2?	
NAT_TOT	Variable	Total national footage	Ft
NET_REV	Variable	Net revenue	K$
NEW_ECAP	Variable	New environmental capital cost	K$
NEW_EOAM	Variable	New environmental O & M cost	K$
NEW_NRES	Variable	New total number of reservoirs	
NGLPRICE	Input	NGL price	$/Gal
NGLPROD	Variable	Annual NGL production	MBbl
NIAT	Variable	Net income after taxes	K$
NIBT	Variable	Net income before taxes	K$
NIBTA	Variable	Net operating income after adjustments before addback	K$
NIL	Input	Net income limitations	K$
NILB	Variable	Net income depletable base	K$
NILL	Input	Net income limitation limit	K$
NOI	Variable	Net operating income	K$
NOM_YEAR	Input	Year for nominal dollars	
NPR_W	Variable	Cost to equip a new producer	K$
NPRA	Estimated	Constant for new producer equipment	
NPRB	Estimated	Constant for new producer equipment	
NPRC	Estimated	Constant for new producer equipment	
NPRK	Estimated	Constant for new producer equipment	
NPRM	Input	Minimum depth range for new producer equations	Ft
NPROD	Variable	Well level NGL production	MMcf
NRDL48	Variable	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF
NREG	Input	Number of regions	

NSHUT	Input	Number of years after economics life in which EOR can be considered	
NTECH	Input	Number of technology impacts	
NUMPACK	Input	Number of packages per play per year	
NWELL	Input	Number of wells in continuous exploration drilling package	
OAM	Variable	Variable O & M cost	K$
OAM_COMP	Variable	Compression O & M	K$
OAM_M	Variable	O & M cost multiplier	
OIA	Variable	Other intangible capital addback	K$
OIL_ADJ	Input	Fraction of annual crude oil drilling which is made available	Fraction
OIL_CASE	Input	Filter for all crude oil processes	
OIL_DWCA	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCB	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCC	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCD	Input	Maximum depth range for crude oil well drilling cost equations	Ft
OIL_DWCK	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCM	Input	Minimum depth range for crude oil well drilling cost equations	Ft
OIL_FILTER	Input	Filter for all crude oil processes	
OIL_OAM	Input	Process specific operating cost for crude oil production	$/Bbl
OIL_RAT_ FAC	Input	Change in crude oil production rate	
OIL_RAT_CHG	Variable	Change in crude oil production rate	
OIL_SALES	Input	Sell crude oil produced from the reservoir?	
OILA0	Estimated	Oil footage A0	
OILA1	Estimated	Oil footage A1	

OILCO2	Input	Fixed crude oil price used for economic pre-screening of industrial CO_2 projects	K$
OILD0	Input	Crude oil drywell footage A0	
OILD1	Input	Crude oil drywell footage A1	
OILPRICEC	Variable	Annual crude oil prices used by cashflow	K$
OILPRICED	Variable	Annual crude oil prices used in the drilling constraints	K$
OILPRICEO	Variable	Annual crude oil prices used by the model	K$
OILPROD	Variable	Annual crude oil production	MBbl
OINJ	Variable	Well level injection	MMcf
OITC	Input	Other intangible tax credit	K$
OITCAB	Input	Other intangible tax credit rate addback	%
OITCR	Input	Other intangible tax credit rate	K$
OMGA	Estimated	Fixed annual cost for natural gas	$/Well
OMGB	Estimated	Fixed annual cost for natural gas	$/Well
OMGC	Estimated	Fixed annual cost for natural gas	$/Well
OMGD	Input	Maximum depth range for fixed annual O & M natural gas cost	Ft
OMGK	Estimated	Constant for fixed annual O & M cost for natural gas	
OMGM	Input	Minimum depth range for fixed annual O & M cost for natural gas	Ft
OML_W	Variable	Variable annual operating cost for lifting	K$
OMLA	Estimated	Lifting cost	$/Well
OMLB	Estimated	Lifting cost	$/Well
OMLC	Estimated	Lifting cost	$/Well
OMLD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMLK	Estimated	Constant for fixed annual operating cost for crude oil	
OMLM	Input	Minimum depth range for annual operating cost for crude oil	Ft
OMO_W	Variable	Fixed annual operating cost for crude oil	K$

OMOA	Estimated	Fixed annual cost for crude oil	$/Well
OMOB	Estimated	Fixed annual cost for crude oil	$/Well
OMOC	Estimated	Fixed annual cost for crude oil	$/Well
OMOD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMOK	Estimated	Constant for fixed annual operating cost for crude oil	
OMOM	Input	Minimum depth range for fixed annual operating cost for crude oil	Ft
OMSWRA	Estimated	Secondary workover cost	$/Well
OMSWRB	Estimated	Secondary workover cost	$/Well
OMSWRC	Estimated	Secondary workover cost	$/Well
OMSWRD	Input	Maximum depth range for variable operating cost for secondary workover	Ft
OMSWRK	Estimated	Constant for variable operating cost for secondary workover	
OMSWRM	Input	Minimum depth range for variable operating cost for secondary workover	Ft
OMULT_INT	Input	Crude oil price adjustment factor, intangible costs	
OMULT_OAM	Input	Crude oil price adjustment factor, O & M	
OMULT_TANG	Input	Crude oil price adjustment factor, tangible costs	
OPCOST	Variable	AOAM by project	K$
OPERL48	Variable	Operating Costs	1987$/Well
OPINJ_W	Variable	Variable annual operating cost for injection	K$
OPINJA	Input	Injection cost	$/Well
OPINJB	Input	Injection cost	$/Well
OPINJC	Input	Injection cost	$/Well
OPINJD	Input	Maximum depth range for variable annual operating cost for injection	Ft
OPINJK	Input	Constant for variable annual operating cost for injection	
OPINJM	Input	Minimum depth range for variable annual operating cost for injection	Ft

OPROD	Variable	Well level crude oil production	MBbl
OPSEC_W	Variable	Fixed annual operating cost for secondary operations	K$
OPSECA	Estimated	Annual cost for secondary production	$/Well
OPSECB	Estimated	Annual cost for secondary production	$/Well
OPSECC	Estimated	Annual cost for secondary production	$/Well
OPSECD	Input	Maximum depth range for fixed annual operating cost for secondary operations	Ft
OPSECK	Estimated	Constant for fixed annual operating cost for secondary operations	
OPSECM	Input	Minimum depth range for fixed annual operating cost for secondary operations	Ft
OPT_RPT	Input	Report printing options	
ORECY	Variable	Well level recycled injectant	MBbl
OTC	Variable	Other tangible costs	K$
PATT_DEV	Input	Pattern development	
PATT_DEV_MAX	Input	Maximum pattern development schedule	
PATT_DEV_MIN	Input	Minimum pattern development schedule	
PATDEV	Variable	Annual number of patterns developed for base and advanced technology	
PATN	Variable	Patterns initiated each year	
PATNDCF	Variable	DCF by project	K$
PATTERNS	Variable	Shifted patterns initiated	
PAYCONT_ FAC	Input	Pay continuity factor	
PDR	Input	Percent depletion rate	%
PGGC	Input	Percent of G & G depleted	%
PIIC	Input	Intangible investment to capitalize	%
PLAC	Input	Percent of lease acquisition cost capitalized	%
PLAYNUM	Input	Play number	
PLY_F	Variable	Cost for a polymer handling plant	K$
PLYPA	Input	Polymer handling plant constant	
PLYPK	Input	Polymer handling plant constant	

POLY	Input	Polymer cost	
POLYCOST	Variable	Polymer cost	$/Lb
POTENTIAL	Variable	The number of reservoirs in the resource file	
PRICEYR	Input	First year of prices in price track	K$
PRO_REGEXP	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGEXPG	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGGAS	Input	Regional natural gas well drilling footage constraint	Ft
PRO_REGOIL	Input	Regional crude oil well drilling footage constraint	Ft
PROB_IMP_FAC	Input	Probability of industrial implementation	
PROB_RD_FAC	Input	Probability of successful R & D	
PROC_CST	Variable	Processing cost	$/Mcf
PROC_OAM	Variable	Processing and treating cost	K$
PROCESS_CASE	Input	Filter for crude oil and natural gas processes	
PROCESS_FILTER	Input	Filter for crude oil and natural gas processes	
PROD_IND_ FAC	Input	Production impact	
PROVACC	Input	Year file for resource access	
PROVNUM	Input	Province number	
PRRATL48	Variable	Production to reserves ratio	Fraction
PSHUT	Input	Number of years prior to economic life in which EOR can be considered	
PSI_W	Variable	Cost to convert a primary well to an injection well	K$
PSIA	Estimated	Cost to convert a producer to an injector	
PSIB	Estimated	Cost to convert a producer to an injector	
PSIC	Estimated	Cost to convert a producer to an injector	
PSID	Input	Maximum depth range for producer to injector	Ft
PSIK	Estimated	Constant for producer to injector	
PSIM	Input	Minimum depth range for producer to injector	Ft
PSW_W	Variable	Cost to convert a primary to secondary well	K$

PSWA	Estimated	Cost to convert a primary to secondary well	
PSWB	Estimated	Cost to convert a primary to secondary well	
PSWC	Estimated	Cost to convert a primary to secondary well	
PSWD	Input	Maximum depth range for producer to injector	Ft
PSWK	Estimated	Constant for primary to secondary	
PSWM	Input	Minimum depth range for producer to injector	Ft
PWHP	Input	Produced water handling plant multiplier	K$
PWP_F	Variable	Cost for a produced water handling plant	K$
RDEPTH	Variable	Reservoir depth	ft
RDR	Input	Depth interval	
RDR_FOOTAGE	Variable	Footage available in this interval	Ft
RDR_FT	Variable	Running total of footage used in this bin	Ft
REC_EFF_ FAC	Input	Recovery efficiency factor	
RECY_OIL	Input	Produced water recycling cost	K$
RECY_WAT	Input	Produced water recycling cost	
REG_DUAL	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
REG_EXP	Variable	Regional exploratory drilling constraints	MBbl/Yr
REG_EXPC	Variable	Regional conventional crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPCG	Variable	Regional conventional natural gas exploratory drilling constraint	Bcf/Yr
REG_EXPG	Variable	Regional exploratory natural gas drilling constraint	Bcf/Yr
REG_EXPU	Variable	Regional continuous crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPUG	Variable	Regional continuous natural gas exploratory drilling constraint	Bcf/Yr
REG_GAS	Variable	Regional natural gas drilling constraint	Bcf/Yr
REG_HADG	Variable	Regional historical AD gas	MMcf
REG_HCBM	Variable	Regional historical CBM	MMcf

REG_HCNV	Variable	Regional historical high-permeability natural gas	MMcf
REG_HEOIL	Variable	Regional crude oil and lease condensates for continuing EOR	MBbl
REG_HGAS	Variable	Regional dry natural gas	MMcf
REG_HOIL	Variable	Regional crude oil and lease condensates	MBbl
REG_HSHL	Variable	Regional historical shale gas	MMcf
REG_HTHT	Variable	Regional historical tight gas	MMcf
REG_NAT	Input	Regional or national	
REG_OIL	Variable	Regional crude oil drilling constraint	MBbl/Yr
REGDRY	Variable	Regional dryhole rate	
REGDRYE	Variable	Exploration regional dryhole rate	
REGDRYG	Variable	Development natural gas regional dryhole rate	
REGDRYKD	Variable	Regional dryhole rate for discovered development	
REGDRYUD	Variable	Regional dryhole rate for undiscovered development	
REGDRYUE	Variable	Regional dryhole rate for undiscovered exploration	
REGION_CASE	Input	Filter for OLOGSS region	
REGION_FILTER	Input	Filter for OLOGSS region	
REGSCALE_CBM	Input	Regional historical daily CBM gas production for the last year of history	Bcf
REGSCALE_CNV	Input	Regional historical daily high-permeability natural gas production for the last year of history	Bcf
REGSCALE_GAS	Input	Regional historical daily natural gas production for the last year of history	Bcf
REGSCALE_OIL	Input	Regional historical daily crude oil production for the last year of history	MBbl
REGSCALE_SHL	Input	Regional historical daily shale gas production for the last year of history	Bcf
REGSCALE_THT	Input	Regional historical daily tight gas production for the last year of history	Bcf
REM_AMOR	Variable	Remaining amortization base	K$
REM_BASE	Variable	Remaining depreciation base	K$

REMRES	Variable	Remaining proven crude oil reserves	MBbl
RESADL48	Variable	Total additions to proved reserves	Oil-MMB Gas-BCF
RESBOYL48	Variable	End of year reserves for current year	Oil-MMB Gas-BCF
RES_CHR_ FAC	Input	Reservoir characterization cost	$/Cumulative BOE
RES_CHR_CHG	Variable	Reservoir characterization cost	$/Cumulative BOE
RESV_ADGAS	Input	Historical AD gas reserves	Tcf
RESV_CBM	Input	Historical coalbed methane reserves	Tcf
RESV_CONVGAS	Input	Historical high-permeability dry natural gas reserves	Tcf
RESV_OIL	Input	Historical crude oil and lease condensate reserves	BBbl
RESV_SHL	Input	Historical shale gas reserves	Tcf
RESV_THT	Input	Historical tight gas reserves	Tcf
RGR	Input	Annual drilling growth rate	
RIGSL48	Variable	Available rigs	Rigs
RNKVAL	Input	Ranking criteria for the projects	
ROR	Variable	Rate of return	K$
ROYALTY	Variable	Royalty	K$
RREG	Variable	Reservoir region	
RRR	Input	Annual drilling retirement rate	
RUNTYPE	Input	Resources selected to evaluate in the Timing subroutine	
RVALUE	Variable	Reservoir technical crude oil production	MBbl
SCALE_DAY	Input	Number of days in the last year of history	Days
SCALE_GAS	Input	Historical daily natural gas production for the last year of history	Bcf
SCALE_OIL	Input	Historical daily crude oil production for the last year of history	MBbl
SEV_PROC	Variable	Process code	
SEV_TAX	Variable	Severance tax	K$
SFIT	Variable	Alternative minimum tax	K$
SKIN_FAC	Input	Skin factor	
SKIN_CHG	Variable	Change in skin amount	
SMAR	Input	Six month amortization rate	%

SPLIT_ED	Input	Split exploration and development	
SPLIT_OG	Input	Split crude oil and natural gas constraints	
STARTPR	Variable	First year a pattern is initiated	
STATE_TAX	Variable	State tax	K$
STIM	Variable	Stimulation cost	K$
STIM_A, STIM_B	Input	Coefficients for natural gas/oil stimulation cost	K$
STIM_W	Variable	Natural gas well stimulation cost	K$
STIM_YR	Input	Number of years between stimulations of natural gas/oil wells	
STIMFAC	Input	Stimulation efficiency factor	
STL	Variable	State identification number	
STMGA	Input	Steam generator cost multiplier	
STMM_F	Variable	Cost for steam manifolds and generators	K$
STMMA	Input	Steam manifold/pipeline multiplier	
SUCCHDEV	Variable	Horizontal development well success rate by region	Fraction
SUCDEVE	Input	Developmental well dryhole rate by region	%
SUCDEVG	Variable	Final developmental natural gas well success rate by region	Fraction
SUCDEVO	Variable	Final developmental crude oil well success rate by region	Fraction
SUCEXP	Input	Undiscovered exploration well dryhole rate by region	%
SUCEXPD	Input	Exploratory well dryhole rate by region	%
SUCG	Variable	Initial developmental natural gas well success rate by region	Fraction
SUCO	Variable	Initial developmental crude oil well success by region	Fraction
SUCWELLL48	Variable	Successful Lower 48 onshore wells drilled	Wells
SUM_DRY	Variable	Developmental dryholes drilled	
SUM_GAS_CONV	Variable	High-permeability natural gas drilling	MMcf

SUM_GAS_UNCONV	Variable	Low-permeability natural gas drilling	MMcf
SUM_OIL_CONV	Variable	Conventional crude oil drilling	MBbl
SUM_OIL_UNCONV	Variable	Continuous crude oil drilling	MBbl
SUMP	Variable	Total cumulative patterns	
SWK_W	Variable	Secondary workover cost	K$
TANG_FAC_RATE	Input	Percentage of the well costs which are tangible	Percent
TANG_M	Variable	Tangible cost multiplier	
TANG_RATE	Input	Percentage of drilling costs which are tangible	Percent
TCI	Variable	Total capital investments	K$
TCIADJ	Variable	Adjusted capital investments	K$
TCOII	Input	Tax credit on intangible investments	K$
TCOTI	Input	Tax credit on tangible investments	K$
TDTC	Input	Tangible development tax credit	K$
TDTCAB	Input	Tangible development tax credit rate addback	%
TDTCR	Input	Tangible development tax credit rate	K$
TECH01_FAC	Input	WAG ratio applied to CO2EOR	
TECH02_FAC	Input	Recovery Limit	
TECH03_FAC	Input	Vertical Skin Factor for natural gas	
TECH04_FAC	Input	Fracture Half Length	Ft
TECH05_FAC	Input	Fracture Conductivity	Ft
TECH_CO2FLD	Variable	Technical production from CO_2 flood	MBbl
TECH_COAL	Variable	Annual technical coalbed methane gas production	MMcf
TECH_CURVE	Variable	Technology commercialization curve for market penetration	
TECH_CURVE_FAC	Input	Technology commercialization curve for market penetration	
TECH_DECLINE	Variable	Technical decline production	MBbl
TECH_GAS	Variable	Annual technical natural gas production	MMcf
TECH_HORCON	Variable	Technical production from horizontal continuity	MBbl

TECH_HORPRF	Variable	Technical production for horizontal profile	MBbl
TECH_INFILL	Variable	Technical production from infill drilling	MBbl
TECH_NGL	Variable	Annual technical NGL production	MBbl
TECH_OIL	Variable	Annual technical crude oil production	MBbl
TECH_PLYFLD	Variable	Technical production from polymer injection	MBbl
TECH_PRFMOD	Variable	Technical production from profile modification	MBbl
TECH_PRIMARY	Variable	Technical production from primary sources	MBbl
TECH_RADIAL	Variable	Technical production from conventional radial flow	MMcf
TECH_SHALE	Variable	Annual technical shale gas production	MMcf
TECH_STMFLD	Variable	Technical production from steam flood	MBbl
TECH_TIGHT	Variable	Annual technical tight gas production	MMcf
TECH_TIGHTG	Variable	Technical tight gas production	MMcf
TECH_UCOALB	Variable	Technical undiscovered coalbed methane production	MMcf
TECH_UCONTO	Variable	Technical undiscovered continuous crude oil production	MBbl
TECH_UCONVG	Variable	Technical low-permeability natural gas production	MMcf
TECH_UCONVO	Variable	Technical undiscovered conventional crude oil production	MBbl
TECH_UGCOAL	Variable	Annual technical developing coalbed methane gas production	MMcf
TECH_UGSHALE	Variable	Annual technical developing shale gas production	MMcf
TECH_UGTIGHT	Variable	Annual technical developing tight gas production	MMcf
TECH_USHALE	Variable	Technical undiscovered shale gas production	MMcf
TECH_UTIGHT	Variable	Technical undiscovered tight gas production	MMcf
TECH_WATER	Variable	Technical production from waterflood	MBbl

TECH_WTRFLD	Variable	Technical production from waterflood	MBbl
TGGLCD	Variable	Total G & G cost	K$
TI	Variable	Tangible costs	K$
TI_DRL	Variable	Tangible drilling cost	K$
TIMED	Variable	Timing flag	
TIMEDYR	Variable	Year in which the project is timed	
TOC	Variable	Total operating costs	K$
TORECY	Variable	Annual water injection	MBbl
TORECY_CST	Variable	Water injection cost	K$
TOTHWCAP	Variable	Total horizontal drilling footage constraint	Ft
TOTINJ	Variable	Annual water injection	MBbl
TOTMUL	Input	Total drilling constraint multiplier	
TOTSTATE	Variable	Total state severance tax	K$
UCNT	Variable	Number of undiscovered reservoirs	
UDEPTH	Variable	Reservoir depth	K$
UMPCO2	Input	CO_2 ultimate market acceptance	
UNAME	Variable	Reservoir identifier	
UNDARES	Variable	Undiscovered resource, AD gas or lease condensate	Bcf, MMBbl
UNDRES	Variable	Undiscovered resource	MMBbl, Bcf
UREG	Variable	Reservoir region	
USE_AVAILCO2	Variable	Used annual volume of CO_2 by region	Bcf
USE_RDR	Input	Use rig depth rating	
USEAVAIL	Variable	Used annual CO_2 volume by region across all sources	Bcf
USECAP	Variable	Annual total capital investment constraints, used by projects	MM$
UVALUE	Variable	Reservoir undiscovered crude oil production	MBbl
UVALUE2	Variable	Reservoir undiscovered natural gas production	MMcf
VEORCP	Input	Volumetric EOR cutoff	%
VIABLE	Variable	The number of economically viable reservoirs	
VOL_SWP_ FAC	Input	Sweep volume factor	
VOL_SWP_CHG	Variable	Change in sweep volume	
WAT_OAM	Input	Process specific operating cost for water production	$/Bbl
WATINJ	Variable	Annual water injection	MBbl

WATPROD	Variable	Annual water production	MBbl
WELLSL48	Variable	Lower 48 onshore wells drilled	Wells
WINJ	Variable	Well level water injection	MBbl
WPROD	Variable	Well level water production	MBbl
WRK_W	Variable	Cost for well workover	K$
WRKA	Estimated	Constant for workover cost equations	
WRKB	Estimated	Constant for workover cost equations	
WRKC	Estimated	Constant for workover cost equations	
WRKD	Input	Maximum depth range for workover cost	Ft
WRKK	Estimated	Constant for workover cost equations	
WRKM	Input	Minimum depth range for workover cost	Ft
XCAPBASE	Variable	Cumulative cap stream	
XCUMPROD	Variable	Cumulative production	MBbl
XPATN	Variable	Active patterns each year	
XPP1	Variable	Number of new producers drilled per pattern	
XPP2	Variable	Number of new injectors drilled per pattern	
XPP3	Variable	Number of producers converted to injectors	
XPP4	Variable	Number of primary wells converted to secondary wells	
XROY	Input	Royalty rate	Percent
YEARS_STUDY	Input	Number of years of analysis	
YR1	Input	Number of years for tax credit on tangible investments	
YR2	Input	Number of years for tax credit on intangible investments	
YRDI	Input	Years to develop infrastructure	
YRDT	Input	Years to develop technology	
YRMA	Input	Years to reach full capacity	

Appendix 2.B: Cost and Constraint Estimation

The major sections of OLOGSS consist of a series of equations that are used to calculate project economics and the development of crude oil and natural gas resources subject to the availability of regional development constraints. The cost and constraint calculation was assessed as unit costs per well. The product of the cost equation and cost adjustment factor is the actual cost. The actual cost reflects the influence on the resource, region and oil or gas price. The equations, the estimation techniques, and the statistical results for these equations are documented below. The statistical software included within Microsoft Excel was used for the estimations.

Drilling and Completion Costs for Crude Oil

The 2004 – 2007 Joint Association Survey (JAS) data was used to calculate the equation for vertical drilling and completion costs for crude oil. The data was analyzed at a regional level. The independent variables were depth, raised to powers of 1 through 3. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below. β1 (the coefficient for depth raised to the first power) is statistically insignificant and is therefore assumed zero.

$$\text{Drilling Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}1)$$

where Drilling Cost = DWC_W
β0 = OIL_DWCK
β1 = OIL_DWCA
β2 = OIL_DWCB
β3 = OIL_DWCC
from equations 2-17 and 2-18 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.836438789
R Square	0.699629848
Adjusted R Square	0.691168717
Standard Error	629377.1735
Observations	74

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	6.55076E+13	3.27538E+13	82.6875087	2.86296E-19
Residual	71	2.81242E+13	3.96116E+11		
Total	73	9.36318E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	122428.578	126464.5594	0.968086068	0.336287616	-129734.7159	374591.8719	-129734.7159	374591.8719
β2	0.058292022	0.020819613	2.799860932	0.006580083	0.016778872	0.099805172	0.016778872	0.099805172
β3	5.68014E-07	2.56497E-06	0.221450391	0.825377435	-4.5464E-06	5.68243E-06	-4.5464E-06	5.68243E-06

Gulf Coast Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.898305188
R Square	0.806952211
Adjusted R Square	0.803343841
Standard Error	865339.0638
Observations	110

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	3.34919E+14	1.67459E+14	223.6334505	6.06832E-39
Residual	107	8.01229E+13	7.48812E+11		
Total	109	4.15042E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	44187.62539	135139.2151	0.326978556	0.744322892	-223710.0994	312085.3502	-223710.0994	312085.3502
β2	0.038468835	0.005870927	6.552429326	2.04023E-09	0.026830407	0.050107263	0.026830407	0.050107263
β3	-9.45921E-07	3.70017E-07	-2.556425591	0.011978314	-1.67944E-06	-2.12405E-07	-1.67944E-06	-2.12405E-07

Southwest Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.905358855
R Square	0.819674657
Adjusted R Square	0.81505093
Standard Error	1524859.577
Observations	81

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	8.24402E+14	4.12201E+14	177.2757561	9.68755E-30
Residual	78	1.81365E+14	2.3252E+12		
Total	80	1.00577E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	85843.77642	334865.8934	0.256352702	0.798353427	-580822.9949	752510.5477	-580822.9949	752510.5477
β2	0.024046279	0.017681623	1.35995883	0.177760898	-0.011155127	0.059247685	-0.011155127	0.059247685
β3	3.11588E-06	1.35985E-06	2.291329746	0.024643617	4.08613E-07	5.82314E-06	4.08613E-07	5.82314E-06

West Coast Region:

Regression Statistics	
Multiple R	0.829042211
R Square	0.687310988
Adjusted R Square	0.66961161
Standard Error	1192282.08
Observations	57

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	1.65605E+14	5.52018E+13	38.83249387	2.05475E-13
Residual	53	7.53414E+13	1.42154E+12		
Total	56	2.40947E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	416130.9988	739996.4118	0.562341914	0.576253925	-1068113.806	1900375.804	-1068113.806	1900375.804
β1	44.24458907	494.4626992	0.089480135	0.929037628	-947.5219666	1036.011145	-947.5219666	1036.011145
β2	0.032683532	0.091113678	0.35871159	0.721235869	-0.150067358	0.215434422	-0.150067358	0.215434422
β3	3.38129E-07	4.76464E-06	0.070966208	0.94369176	-9.21853E-06	9.89479E-06	-9.21853E-06	9.89479E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.847120174
R Square	0.71761259
Adjusted R Square	0.702750095
Standard Error	1967213.576
Observations	61

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	5.60561E+14	1.86854E+14	48.2834529	1.1626E-15
Residual	57	2.20586E+14	3.86993E+12		
Total	60	7.81147E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	98507.54357	1384010.586	0.071175426	0.943507284	-2672925.83	2869940.917	-2672925.83	2869940.917
β1	478.7358996	548.203512	0.873281344	0.386173991	-619.0226893	1576.494489	-619.0226893	1576.494489
β2	-0.00832112	0.058193043	-0.142991666	0.886801051	-0.124850678	0.108208438	-0.124850678	0.108208438
β3	6.1159E-07	1.79131E-06	0.34142064	0.7340424	-2.97545E-06	4.19863E-06	-2.97545E-06	4.19863E-06

Drilling and Completion Cost for Oil - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for oil was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.993325966
R Square	0.986696475
Adjusted R Square	0.986411399
Standard Error	0.029280014
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.901997029	2.967332343	3461.175482	4.4887E-131
Residual	140	0.120024694	0.000857319		
Total	143	9.022021723			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309616442	0.009839962	31.46520591	2.3349E-65	0.290162308	0.329070576	0.290162308	0.329070576
β1	0.019837121	0.000434252	45.68110123	5.41725E-86	0.018978581	0.020695661	0.018978581	0.020695661
β2	-0.000142411	5.21769E-06	-27.29392193	6.44605E-58	-0.000152727	-0.000132095	-0.000152727	-0.000132095
β3	3.45898E-07	1.69994E-08	20.34770764	1.18032E-43	3.1229E-07	3.79507E-07	3.1229E-07	3.79507E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.975220111
R Square	0.951054265
Adjusted R Square	0.950005428
Standard Error	0.054224144
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.998414341	2.666138114	906.7701736	1.76449E-91
Residual	140	0.411636098	0.002940258		
Total	143	8.410050438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.404677859	0.01822279	22.2072399	1.01029E-47	0.368650426	0.440705292	0.368650426	0.440705292
β1	0.016335847	0.000804199	20.31319148	1.41023E-43	0.014745903	0.017925792	0.014745903	0.017925792
β2	-0.00010587	9.66272E-06	-10.95654411	1.47204E-20	-0.000124974	-8.67663E-05	-0.000124974	-8.67663E-05
β3	2.40517E-07	3.14814E-08	7.639970947	3.10789E-12	1.78277E-07	3.02758E-07	1.78277E-07	3.02758E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993452577
R Square	0.986948023
Adjusted R Square	0.986668338
Standard Error	0.030207623
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.66004438	3.220014793	3528.781511	1.1799E-131
Residual	140	0.127750066	0.0009125		
Total	143	9.787794446			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.293837119	0.010151698	28.944627	5.92751E-61	0.273766667	0.313907571	0.273766667	0.313907571
β1	0.020183122	0.00044801	45.05064425	3.35207E-85	0.019297383	0.021068861	0.019297383	0.021068861
β2	-0.000142936	5.38299E-06	-26.55334755	1.63279E-56	-0.000153579	-0.000132294	-0.000153579	-0.000132294
β3	3.44926E-07	1.75379E-08	19.66744699	4.04901E-42	3.10253E-07	3.796E-07	3.10253E-07	3.796E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.993622433
R Square	0.987285538
Adjusted R Square	0.987013086
Standard Error	0.029478386
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.446702681	3.148900894	3623.69457	1.8856E-132
Residual	140	0.121656535	0.000868975		
Total	143	9.568359216			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.297270516	0.009906628	30.00723517	7.63744E-63	0.27768458	0.316856451	0.27768458	0.316856451
β1	0.020126228	0.000437194	46.03497443	1.9664E-86	0.019261872	0.020990585	0.019261872	0.020990585
β2	-0.000143079	5.25304E-06	-27.23739215	8.23219E-58	-0.000153465	-0.000132693	-0.000153465	-0.000132693
β3	3.45557E-07	1.71145E-08	20.19080817	2.6538E-43	3.1172E-07	3.79393E-07	3.1172E-07	3.79393E-07

West Coast Region:

Regression Statistics	
Multiple R	0.993362569
R Square	0.986769193
Adjusted R Square	0.986485676
Standard Error	0.030158697
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.496912448	3.165637483	3480.455028	3.0585E-131
Residual	140	0.127336582	0.000909547		
Total	143	9.62424903			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.297702178	0.010135256	29.37293095	1.01194E-61	0.277664233	0.317740124	0.277664233	0.317740124
β1	0.020091425	0.000447284	44.91872099	4.92225E-85	0.019207121	0.02097573	0.019207121	0.02097573
β2	-0.000142627	5.37427E-06	-26.53879345	1.74092E-56	-0.000153252	-0.000132001	-0.000153252	-0.000132001
β3	3.44597E-07	1.75095E-08	19.68054067	3.78057E-42	3.0998E-07	3.79214E-07	3.0998E-07	3.79214E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993744864
R Square	0.987528854
Adjusted R Square	0.987261615
Standard Error	0.029293844
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.513146663	3.171048888	3695.304354	4.8762E-133
Residual	140	0.1201381	0.000858129		
Total	143	9.633284764			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.292784596	0.00984461	29.74059899	2.25193E-62	0.273321274	0.312247919	0.273321274	0.312247919
β1	0.020415818	0.000434457	46.99153447	1.31433E-87	0.019556872	0.021274763	0.019556872	0.021274763
β2	-0.000146385	5.22015E-06	-28.04230529	2.6131E-59	-0.000156706	-0.000136065	-0.000156706	-0.000136065
β3	3.5579E-07	1.70074E-08	20.91972526	6.3186E-45	3.22166E-07	3.89415E-07	3.22166E-07	3.89415E-07

Drilling and Completion Costs for Natural Gas

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for natural gas. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}2)$$

where Drilling Cost = DWC_W
β0 = GAS_DWCK
β1 = GAS_DWCA
β2 = GAS_DWCB
β3 = GAS_DWCC
from equations 2-24 and 2-25 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.837701882
R Square	0.701744444
Adjusted R Square	0.694887994
Standard Error	1199562.042
Observations	90

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.94547E+14	1.47274E+14	102.3480792	1.39509E-23
Residual	87	1.25189E+14	1.43895E+12		
Total	89	4.19736E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	197454.5012	290676.607	0.679292714	0.498755704	-380296.7183	775205.7207	-380296.7183	775205.7207
β1	19.31146768	128.263698	0.150560665	0.880670823	-235.6265154	274.2494508	-235.6265154	274.2494508
β2	0.040120878	0.009974857	4.022200679	0.000122494	0.020294769	0.059946987	0.020294769	0.059946987

Gulf Coast Region:

Regression Statistics	
Multiple R	0.842706997
R Square	0.710155083
Adjusted R Square	0.708248209
Standard Error	2573551.438
Observations	307

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.93318E+15	2.46659E+15	372.4183744	1.77494E-82
Residual	304	2.01344E+15	6.62317E+12		
Total	306	6.94662E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	318882.7578	272026.272	1.172249855	0.242014577	-216410.0169	854175.5325	-216410.0169	854175.5325
β2	0.019032113	0.008289474	2.295937192	0.022359763	0.002720101	0.035344125	0.002720101	0.035344125
β3	1.12638E-06	4.6744E-07	2.409676918	0.016560642	2.06552E-07	2.04621E-06	2.06552E-07	2.04621E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.92348831
R Square	0.852830659
Adjusted R Square	0.850494637
Standard Error	1309841.335
Observations	129

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.25272E+15	6.26359E+14	365.0782904	3.73674E-53
Residual	126	2.16176E+14	1.71568E+12		
Total	128	1.46889E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	355178.8049	240917.4549	1.47427593	0.142901467	-121589.7497	831947.3594	-121589.7497	831947.3594
β1	54.21184769	45.96361807	1.17945127	0.240440741	-36.74880003	145.1724954	-36.74880003	145.1724954
β3	1.20269E-06	1.12352E-07	10.70467954	2.04711E-19	9.80347E-07	1.42503E-06	9.80347E-07	1.42503E-06

Southwest Region:

Regression Statistics	
Multiple R	0.915492169
R Square	0.838125912
Adjusted R Square	0.834866702
Standard Error	1386872.99
Observations	153

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	1.48386E+15	4.94618E+14	257.1561693	1.088E-58
Residual	149	2.86589E+14	1.92342E+12		
Total	152	1.77044E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	91618.176	571133.886	0.160414534	0.872771817	-1036949.89	1220186.242	-1036949.89	1220186.242
β1	376.1968481	269.4896391	1.395960339	0.164802951	-156.3182212	908.7119175	-156.3182212	908.7119175
β2	-0.062403125	0.034837969	-1.791238896	0.075284827	-0.131243411	0.00643716	-0.131243411	0.00643716
β3	5.03882E-06	1.29778E-06	3.88265606	0.000154832	2.4744E-06	7.60325E-06	2.4744E-06	7.60325E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.936745489
R Square	0.877492112
Adjusted R Square	0.87539796
Standard Error	2403080.549
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.83951E+15	2.41976E+15	419.0202716	4.54566E-54
Residual	117	6.75651E+14	5.7748E+12		
Total	119	5.51516E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	219733.2637	346024.9678	0.635021412	0.526654367	-465551.0299	905017.5572	-465551.0299	905017.5572
β2	0.032265399	0.013130355	2.457313594	0.015464796	0.00626142	0.058269377	0.00626142	0.058269377
β3	2.6019E-06	7.88034E-07	3.301759413	0.001274492	1.04124E-06	4.16256E-06	1.04124E-06	4.16256E-06

West Coast Region:

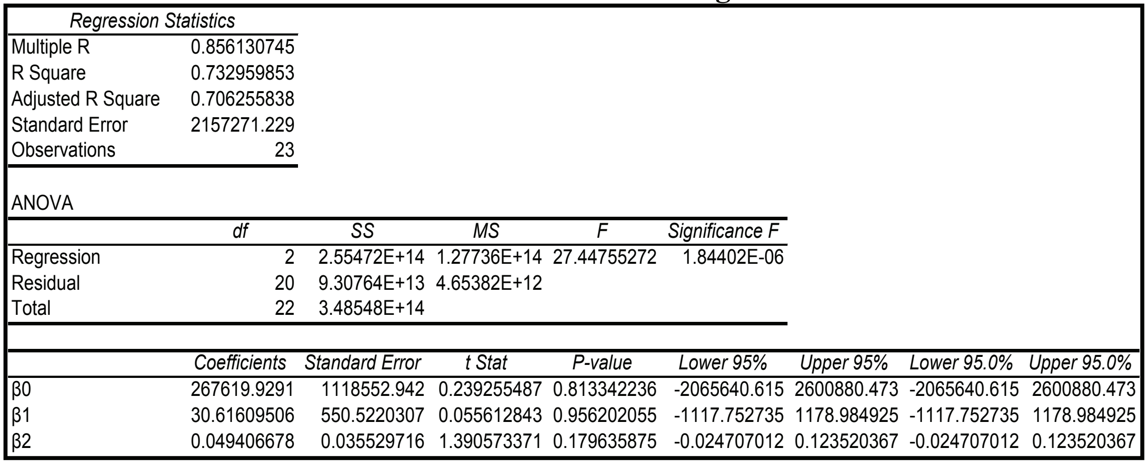
Regression Statistics	
Multiple R	0.901854712
R Square	0.813341922
Adjusted R Square	0.795564962
Standard Error	494573.0787
Observations	24

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.23824E+13	1.11912E+13	45.75258814	2.21815E-08
Residual	21	5.13665E+12	2.44603E+11		
Total	23	2.75191E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	385532.8938	215673.5911	1.787575808	0.088286514	-62984.89058	834050.6782	-62984.89058	834050.6782
β2	0.01799366	0.016370041	1.099182335	0.284130777	-0.016049704	0.052037025	-0.016049704	0.052037025
β3	1.01127E-06	1.49488E-06	0.676491268	0.506112235	-2.0975E-06	4.12005E-06	-2.0975E-06	4.12005E-06

Northern Great Plains Region:



Regression Statistics	
Multiple R	0.856130745
R Square	0.732959853
Adjusted R Square	0.706255838
Standard Error	2157271.229
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.55472E+14	1.27736E+14	27.44755272	1.84402E-06
Residual	20	9.30764E+13	4.65382E+12		
Total	22	3.48548E+14			

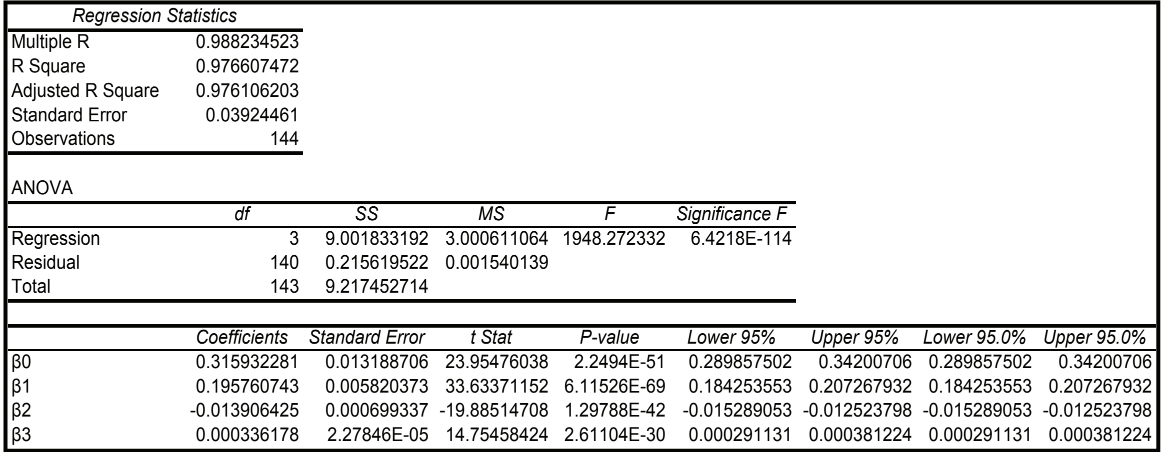
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	267619.9291	1118552.942	0.239255487	0.813342236	-2065640.615	2600880.473	-2065640.615	2600880.473
β1	30.61609506	550.5220307	0.055612843	0.956202055	-1117.752735	1178.984925	-1117.752735	1178.984925
β2	0.049406678	0.035529716	1.390573371	0.179635875	-0.024707012	0.123520367	-0.024707012	0.123520367

Drilling and Completion Cost for Gas - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for gas was calculated using JAS data through 2007. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Gas Price} + \beta2 * \text{Gas Price}^2 + \beta3 * \text{Gas Price}^3$$

Northeast Region:



Regression Statistics	
Multiple R	0.988234523
R Square	0.976607472
Adjusted R Square	0.976106203
Standard Error	0.03924461
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.001833192	3.000611064	1948.272332	6.4218E-114
Residual	140	0.215619522	0.001540139		
Total	143	9.217452714			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.315932281	0.013188706	23.95476038	2.2494E-51	0.289857502	0.34200706	0.289857502	0.34200706
β1	0.195760743	0.005820373	33.63371152	6.11526E-69	0.184253553	0.207267932	0.184253553	0.207267932
β2	-0.013906425	0.000699337	-19.88514708	1.29788E-42	-0.015289053	-0.012523798	-0.015289053	-0.012523798
β3	0.000336178	2.27846E-05	14.75458424	2.61104E-30	0.000291131	0.000381224	0.000291131	0.000381224

Gulf Coast Region:

Regression Statistics	
Multiple R	0.976776879
R Square	0.954093072
Adjusted R Square	0.953109352
Standard Error	0.051120145
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.60369517	2.534565057	969.8828784	1.98947E-93
Residual	140	0.365857688	0.002613269		
Total	143	7.969552858			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343645899	0.017179647	20.00308313	7.02495E-43	0.309680816	0.377610983	0.309680816	0.377610983
β1	0.190338822	0.007581635	25.10524794	1.08342E-53	0.175349523	0.205328121	0.175349523	0.205328121
β2	-0.013965513	0.000910959	-15.33056399	9.3847E-32	-0.015766527	-0.012164498	-0.015766527	-0.012164498
β3	0.000342962	2.96793E-05	11.55560459	4.15963E-22	0.000284285	0.00040164	0.000284285	0.00040164

Mid-continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.966438524
R Square	0.934003421
Adjusted R Square	0.932589209
Standard Error	0.06631093
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.712149531	2.904049844	660.4406967	2.13407E-82
Residual	140	0.615599523	0.004397139		
Total	143	9.327749054			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.323862308	0.022284725	14.53292844	9.46565E-30	0.279804211	0.367920404	0.279804211	0.367920404
β1	0.193832047	0.009834582	19.70923084	3.2532E-42	0.174388551	0.213275544	0.174388551	0.213275544
β2	-0.013820723	0.001181658	-11.69604336	1.80171E-22	-0.016156924	-0.011484522	-0.016156924	-0.011484522
β3	0.000334693	3.84988E-05	8.693602923	8.44808E-15	0.000258579	0.000410807	0.000258579	0.000410807

Rocky Mountains Region:

Regression Statistics	
Multiple R	0.985593617
R Square	0.971394777
Adjusted R Square	0.970781808
Standard Error	0.0421446
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.444274294	2.814758098	1584.737059	8.3614E-108
Residual	140	0.248663418	0.001776167		
Total	143	8.692937712			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32536782	0.014163288	22.97261928	2.42535E-49	0.29736624	0.353369401	0.29736624	0.353369401
β1	0.194045615	0.006250471	31.04496067	1.21348E-64	0.181688099	0.206403131	0.181688099	0.206403131
β2	-0.01396687	0.000751015	-18.59732564	1.18529E-39	-0.015451667	-0.012482073	-0.015451667	-0.012482073
β3	0.000339698	2.44683E-05	13.88318297	4.22503E-28	0.000291323	0.000388073	0.000291323	0.000388073

West Coast Region:

Regression Statistics	
Multiple R	0.994143406
R Square	0.988321112
Adjusted R Square	0.98807085
Standard Error	0.026802603
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.510960152	2.836986717	3949.147599	4.9307E-135
Residual	140	0.100573131	0.00071838		
Total	143	8.611533284			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325917293	0.009007393	36.18330938	6.29717E-73	0.308109194	0.343725393	0.308109194	0.343725393
β1	0.193657091	0.003975097	48.71757347	1.12458E-89	0.185798111	0.201516072	0.185798111	0.201516072
β2	-0.013893214	0.000477621	-29.08835053	3.2685E-61	-0.014837497	-0.012948932	-0.014837497	-0.012948932
β3	0.000337413	1.5561E-05	21.68318808	1.35414E-46	0.000306648	0.000368178	0.000306648	0.000368178

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.970035104
R Square	0.940968103
Adjusted R Square	0.939703134
Standard Error	0.057035843
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.259587116	2.419862372	743.8663996	8.71707E-86
Residual	140	0.455432229	0.003253087		
Total	143	7.715019345			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.352772153	0.0191677	18.40451098	3.34838E-39	0.31487658	0.390667726	0.31487658	0.390667726
β1	0.189510541	0.008458993	22.40344064	3.85701E-48	0.172786658	0.206234423	0.172786658	0.206234423
β2	-0.014060192	0.001016376	-13.83364754	5.65155E-28	-0.016069622	-0.012050761	-0.016069622	-0.012050761
β3	0.000347364	3.31138E-05	10.49000322	2.34854E-19	0.000281896	0.000412832	0.000281896	0.000412832

Drilling and Completion Costs for Dryholes

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for dryholes. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given bellow.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}3)$$

where Drilling Cost = DWC_W
β0 = DRY_DWCK
β1 = DRY_DWCA
β2 = DRY_DWCB
β3 = DRY_DWCC
from equations 2-19 and 2-20 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.913345218
R Square	0.834199487
Adjusted R Square	0.828851084
Standard Error	1018952.27
Observations	97

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4.85819E+14	1.6194E+14	155.9716777	3.64706E-36
Residual	93	9.65585E+13	1.03826E+12		
Total	96	5.82378E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	170557.6447	323739.1839	0.526836581	0.599561475	-472323.5706	813438.8601	-472323.5706	813438.8601
β1	256.9930321	233.0025772	1.102962187	0.272889552	-205.7034453	719.6895095	-205.7034453	719.6895095
β2	-0.043428533	0.043117602	-1.007211224	0.31644672	-0.129051459	0.042194394	-0.129051459	0.042194394
β3	5.9031E-06	2.11581E-06	2.789995653	0.006394574	1.70153E-06	1.01047E-05	1.70153E-06	1.01047E-05

Gulf Coast Region:

Regression Statistics	
Multiple R	0.868545327
R Square	0.754370985
Adjusted R Square	0.752096642
Standard Error	2529468.051
Observations	328

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.36662E+15	2.12221E+15	331.6874692	2.10256E-98
Residual	324	2.07302E+15	6.39821E+12		
Total	327	8.43964E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	118790.7619	515360.6337	0.230500264	0.81784853	-895084.76	1132666.284	-895084.76	1132666.284
β1	126.2333724	241.1698405	0.523421055	0.601039076	-348.2231187	600.6898634	-348.2231187	600.6898634
β2	-0.001057252	0.0294162	-0.035941139	0.971351426	-0.058928115	0.056813612	-0.058928115	0.056813612
β3	2.32104E-06	1.0194E-06	2.276864977	0.02344596	3.15558E-07	4.32653E-06	3.15558E-07	4.32653E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.80373002
R Square	0.645981944
Adjusted R Square	0.636056204
Standard Error	904657.9939
Observations	111

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	1.59789E+14	5.32631E+13	65.08149035	5.0095E-24
Residual	107	8.75695E+13	8.18406E+11		
Total	110	2.47359E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	163849.8824	309404.7345	0.529564884	0.597510699	-449508.8999	777208.6646	-449508.8999	777208.6646
β1	17.95111978	155.7546455	0.115252548	0.908460959	-290.8142902	326.7165297	-290.8142902	326.7165297
β2	0.022715716	0.021144885	1.074288957	0.285109837	-0.019201551	0.064632983	-0.019201551	0.064632983
β3	-3.50301E-07	7.90957E-07	-0.442882115	0.658745077	-1.91828E-06	1.21768E-06	-1.91828E-06	1.21768E-06

Southwest Region:

Regression Statistics	
Multiple R	0.916003396
R Square	0.839062222
Adjusted R Square	0.835290243
Standard Error	734795.4183
Observations	132

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	3.60312E+14	1.20104E+14	222.4461445	1.40193E-50
Residual	128	6.91103E+13	5.39924E+11		
Total	131	4.29423E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	22628.66985	252562.1046	0.089596457	0.928747942	-477108.2352	522365.5749	-477108.2352	522365.5749
β1	262.7649266	164.1391792	1.600866581	0.111871702	-62.01224262	587.5420958	-62.01224262	587.5420958
β2	-0.064989728	0.029352301	-2.21412721	0.02859032	-0.123068227	-0.006911229	-0.123068227	-0.006911229
β3	6.52693E-06	1.49073E-06	4.378340081	2.46095E-05	3.57727E-06	9.4766E-06	3.57727E-06	9.4766E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.908263682
R Square	0.824942917
Adjusted R Square	0.821295894
Standard Error	1868691.311
Observations	99

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1.57976E+15	7.89879E+14	226.1962739	4.70571E-37
Residual	96	3.35233E+14	3.49201E+12		
Total	98	1.91499E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	288056.5506	314517.8483	0.915867103	0.362031526	-336256.4285	912369.5298	-336256.4285	912369.5298
β2	0.018141347	0.017298438	1.048727458	0.296936644	-0.01619578	0.052478474	-0.01619578	0.052478474
β3	3.85847E-06	1.27201E-06	3.033362592	0.003110773	1.33355E-06	6.3834E-06	1.33355E-06	6.3834E-06

West Coast Region:

Regression Statistics	
Multiple R	0.853182771
R Square	0.727920841
Adjusted R Square	0.707514904
Standard Error	907740.218
Observations	44

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.81804E+13	2.93935E+13	35.67201271	2.18647E-11
Residual	40	3.29597E+13	8.23992E+11		
Total	43	1.2114E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	106996.0572	512960.104	0.208585534	0.835830348	-929734.9747	1143727.089	-929734.9747	1143727.089
β1	687.3095347	329.4149478	2.086455212	0.043357214	21.53709715	1353.081972	21.53709715	1353.081972
β2	-0.15898723	0.058188911	-2.732259905	0.009317504	-0.276591406	-0.041383054	-0.276591406	-0.041383054
β3	1.14978E-05	2.91968E-06	3.938046272	0.000320309	5.59694E-06	1.73987E-05	5.59694E-06	1.73987E-05

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.841621294
R Square	0.708326403
Adjusted R Square	0.687977082
Standard Error	2155533.512
Observations	47

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4.85193E+14	1.61731E+14	34.80835607	1.41404E-11
Residual	43	1.99792E+14	4.64632E+12		
Total	46	6.84985E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	122507.9534	1373015.289	0.089225484	0.929317007	-2646441.235	2891457.142	-2646441.235	2891457.142
β1	345.4371452	801.6324436	0.430917122	0.668681154	-1271.20873	1962.08302	-1271.20873	1962.08302
β2	-0.014734575	0.126273194	-0.11668807	0.907650548	-0.269388738	0.239919588	-0.269388738	0.239919588
β3	3.23748E-06	5.69952E-06	0.568026219	0.572971531	-8.2567E-06	1.47317E-05	-8.2567E-06	1.47317E-05

Drilling and Completion Cost for Dry - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for dryholes was calculated using JAS data through 2007. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.994846264
R Square	0.989719089
Adjusted R Square	0.989498783
Standard Error	0.026930376
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.774469405	3.258156468	4492.489925	6.5663E-139
Residual	140	0.101534319	0.000725245		
Total	143	9.876003725			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.290689859	0.009050333	32.11924425	1.85582E-66	0.272796865	0.308582854	0.272796865	0.308582854
β1	0.020261651	0.000399405	50.72962235	5.26469E-92	0.019472006	0.021051296	0.019472006	0.021051296
β2	-0.000143294	4.79898E-06	-29.85918012	1.391E-62	-0.000152782	-0.000133806	-0.000152782	-0.000133806
β3	3.45487E-07	1.56352E-08	22.09672004	1.74153E-47	3.14575E-07	3.76399E-07	3.14575E-07	3.76399E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.993347128
R Square	0.986738516
Adjusted R Square	0.986454342
Standard Error	0.031666016
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.44539464	3.481798214	3472.296057	3.5967E-131
Residual	140	0.140383119	0.001002737		
Total	143	10.58577776			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.277940175	0.010641812	26.11774938	1.12431E-55	0.256900742	0.298979608	0.256900742	0.298979608
β1	0.020529977	0.000469639	43.71437232	1.71946E-83	0.019601475	0.021458479	0.019601475	0.021458479
β2	-0.000143466	5.64287E-06	-25.42421447	2.53682E-54	-0.000154622	-0.000132309	-0.000154622	-0.000132309
β3	3.43878E-07	1.83846E-08	18.70465533	6.66256E-40	3.07531E-07	3.80226E-07	3.07531E-07	3.80226E-07

Mid-Continent Region:

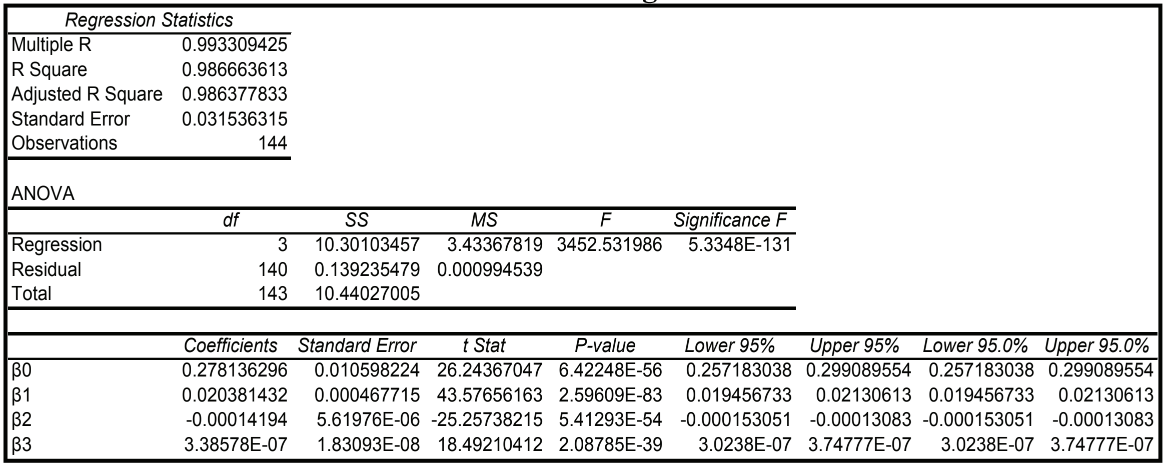
Regression Statistics	
Multiple R	0.984006541
R Square	0.968268874
Adjusted R Square	0.967588921
Standard Error	0.048034262
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.856909541	3.285636514	1424.023848	1.1869E-104
Residual	140	0.323020652	0.00230729		
Total	143	10.17993019			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.289971748	0.016142592	17.96314638	3.67032E-38	0.258056977	0.32188652	0.258056977	0.32188652
β1	0.020266191	0.000712397	28.44789972	4.71502E-60	0.018857744	0.021674637	0.018857744	0.021674637
β2	-0.000143007	8.55969E-06	-16.70702184	3.8001E-35	-0.00015993	-0.000126084	-0.00015993	-0.000126084
β3	3.44462E-07	2.78877E-08	12.35174476	3.63124E-24	2.89326E-07	3.99597E-07	2.89326E-07	3.99597E-07

Southwest Region:



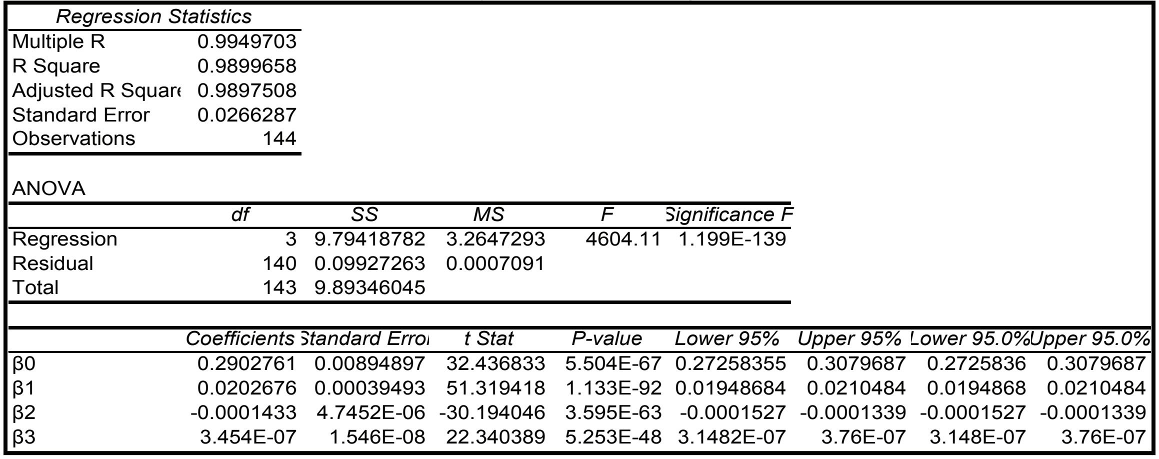
Regression Statistics	
Multiple R	0.993309425
R Square	0.986663613
Adjusted R Square	0.986377833
Standard Error	0.031536315
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.30103457	3.43367819	3452.531986	5.3348E-131
Residual	140	0.139235479	0.000994539		
Total	143	10.44027005			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.278136296	0.010598224	26.24367047	6.42248E-56	0.257183038	0.299089554	0.257183038	0.299089554
β1	0.020381432	0.000467715	43.57656163	2.59609E-83	0.019456733	0.02130613	0.019456733	0.02130613
β2	-0.00014194	5.61976E-06	-25.25738215	5.41293E-54	-0.000153051	-0.00013083	-0.000153051	-0.00013083
β3	3.38578E-07	1.83093E-08	18.49210412	2.08785E-39	3.0238E-07	3.74777E-07	3.0238E-07	3.74777E-07

Rocky Mountain Region:



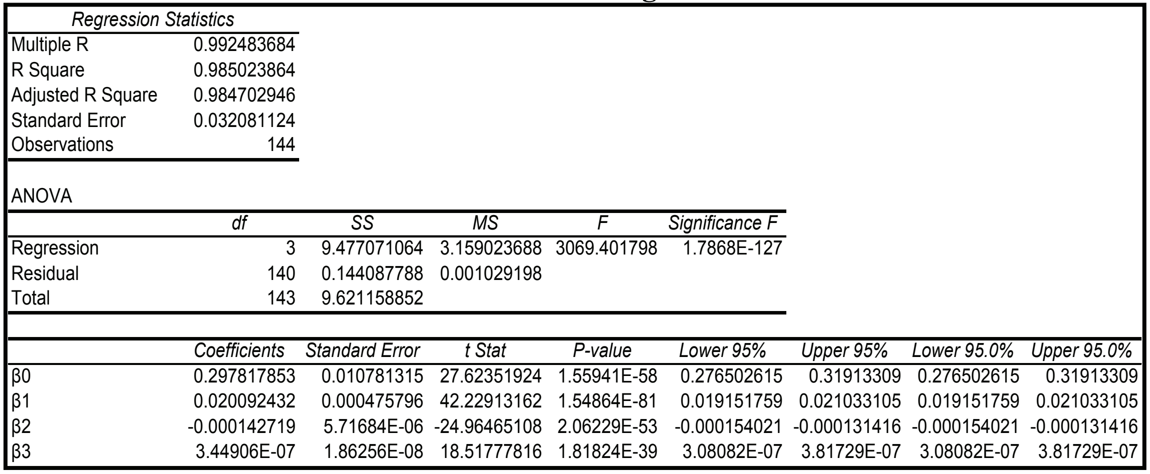
Regression Statistics	
Multiple R	0.9949703
R Square	0.9899658
Adjusted R Squar	0.9897508
Standard Error	0.0266287
Observations	144

ANOVA

	df	SS	MS	F	ignificance F
Regression	3	9.79418782	3.2647293	4604.11	1.199E-139
Residual	140	0.09927263	0.0007091		
Total	143	9.89346045			

	Coefficients	tandard Erro	t Stat	P-value	Lower 95%	Upper 95%	ower 95.0%	Upper 95.0%
β0	0.2902761	0.00894897	32.436833	5.504E-67	0.27258355	0.3079687	0.2725836	0.3079687
β1	0.0202676	0.00039493	51.319418	1.133E-92	0.01948684	0.0210484	0.0194868	0.0210484
β2	-0.0001433	4.7452E-06	-30.194046	3.595E-63	-0.0001527	-0.0001339	-0.0001527	-0.0001339
β3	3.454E-07	1.546E-08	22.340389	5.253E-48	3.1482E-07	3.76E-07	3.148E-07	3.76E-07

West Coast Region:



Regression Statistics	
Multiple R	0.992483684
R Square	0.985023864
Adjusted R Square	0.984702946
Standard Error	0.032081124
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.477071064	3.159023688	3069.401798	1.7868E-127
Residual	140	0.144087788	0.001029198		
Total	143	9.621158852			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297817853	0.010781315	27.62351924	1.55941E-58	0.276502615	0.31913309	0.276502615	0.31913309
β1	0.020092432	0.000475796	42.22913162	1.54864E-81	0.019151759	0.021033105	0.019151759	0.021033105
β2	-0.000142719	5.71684E-06	-24.96465108	2.06229E-53	-0.000154021	-0.000131416	-0.000154021	-0.000131416
β3	3.44906E-07	1.86256E-08	18.51777816	1.81824E-39	3.08082E-07	3.81729E-07	3.08082E-07	3.81729E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993525621
R Square	0.987093159
Adjusted R Square	0.986816584
Standard Error	0.031179889
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.40915184	3.469717279	3568.986978	5.3943E-132
Residual	140	0.136105966	0.000972185		
Total	143	10.5452578			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.281568556	0.010478442	26.87122338	4.04796E-57	0.260852113	0.302284998	0.260852113	0.302284998
β1	0.020437386	0.000462429	44.19569691	4.11395E-84	0.019523138	0.021351633	0.019523138	0.021351633
β2	-0.000142671	5.55624E-06	-25.67758357	8.07391E-55	-0.000153656	-0.000131686	-0.000153656	-0.000131686
β3	3.42012E-07	1.81024E-08	18.89319503	2.43032E-40	3.06223E-07	3.77802E-07	3.06223E-07	3.77802E-07

Drilling and Completion Costs for Horizontal Wells

The costs of horizontal drilling for crude oil, natural gas, and dryholes are based upon cost estimates developed for the Department of Energy's Comprehensive Oil and Gas Analysis Model. The form of the equation is as follows:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth}^2 + \beta2 * \text{Depth}^2 * \text{nlat} + \beta3 * \text{Depth}^2 * \text{nlat} * \text{latlen} \tag{2.B-4}$$

Where, nlat is the number of laterals per pattern and latlen is the length of those laterals. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Regression Statistics	
Multiple R	1
R Square	1
Adjusted R Square	1
Standard Error	3.12352E-12
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	3	147,510,801.46	49,170,267.15	5.04E+30	0.00
Residual	116	0.00	0.00		
Total	119	147,510,801.46			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	172.88	4.37E-13	3.95E+14	0.00	172.88	172.88	172.88	172.88
β1	8.07E-06	8.81E-21	9.16E+14	0.00	8.07E-06	8.07E-06	8.07E-06	8.07E-06
β2	1.15E-06	3.20E-21	3.60E+14	0.00	1.15E-06	1.15E-06	1.15E-06	1.15E-06
β3	9.22E-10	1.48E-24	6.23E+14	0.00	9.22E-10	9.22E-10	9.22E-10	9.22E-10

Cost to Equip a Primary Producer

The cost to equip a primary producer was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The cost to equip a primary producer is equal to the grand total cost minus the producing equipment subtotal. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}5)$$

where Cost = NPR_W
$\beta 0$ = NPRK
$\beta 1$ = NPRA
$\beta 2$ = NPRB
$\beta 3$ = NPRC
from equation 2-21 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS regions 2 and 4:

Regression Statistics	
Multiple R	0.921
R Square	0.849
Adjusted R Square	0.697
Standard Error	621.17
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,163,010.81	2,163,010.81	5.61	0.254415
Residual	1	385,858.01	385,858.01		
Total	2	2,548,868.81			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	51,315.4034	760.7805	67.4510	0.0094	41,648.8117	60,981.9952	41,648.8117	60,981.9952
β1	0.3404	0.1438	2.3676	0.2544	-1.4864	2.1672	-1.4864	2.1672

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.995
R Square	0.990
Adjusted R Square	0.981
Standard Error	1,193.14
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	145,656,740.81	145,656,740.81	102.32	0.06
Residual	1	1,423,576.87	1,423,576.87		
Total	2	147,080,317.68			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	45,821.717	1,461.289	31.357	0.020	27,254.360	64,389.074	27,254.360	64,389.074
β1	2.793	0.276	10.115	0.063	-0.716	6.302	-0.716	6.302

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9998
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	224.46
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	105,460,601.42	105,460,601.42	2,093.17	0.01
Residual	1	50,383.23	50,383.23		
Total	2	105,510,984.64			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	62,709.378	274.909	228.110	0.003	59,216.346	66,202.411	59,216.346	66,202.411
β1	2.377	0.052	45.751	0.014	1.717	3.037	1.717	3.037

West Coast, applied to OLOGSS regions 6:

Regression Statistics	
Multiple R	0.9095
R Square	0.8272
Adjusted R Square	0.7408
Standard Error	2,257.74
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,812,671.60	48,812,671.60	9.58	0.09
Residual	2	10,194,785.98	5,097,392.99		
Total	3	59,007,457.58			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	106,959.788	2,219.144	48.199	0.000	97,411.576	116,508.001	97,411.576	116,508.001
β1	0.910	0.294	3.095	0.090	-0.355	2.174	-0.355	2.174

Cost to Equip a Primary Producer - Cost Adjustment Factor

The cost adjustment factor for the cost to equip a primary producer was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994410537
R Square	0.988852316
Adjusted R Square	0.988613437
Standard Error	0.026443679
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.683975313	2.894658438	4139.554242	1.896E-136
Residual	140	0.097897541	0.000699268		
Total	143	8.781872854			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31969898	0.008886772	35.97470366	1.30857E-72	0.302129355	0.337268604	0.302129355	0.337268604
β1	0.01951727	0.000392187	49.76527469	6.72079E-91	0.018741896	0.020292644	0.018741896	0.020292644
β2	-0.000139868	4.71225E-06	-29.68181785	2.86084E-62	-0.000149185	-0.000130552	-0.000149185	-0.000130552
β3	3.39583E-07	1.53527E-08	22.11882142	1.56166E-47	3.0923E-07	3.69936E-07	3.0923E-07	3.69936E-07

South Texas, Applied to OLOGSS Regions 2:

Regression Statistics	
Multiple R	0.994238324
R Square	0.988509845
Adjusted R Square	0.988263627
Standard Error	0.026795052
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.647535343	2.882511781	4014.781289	1.5764E-135
Residual	140	0.100516472	0.000717975		
Total	143	8.748051814			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320349357	0.009004856	35.57517997	5.36201E-72	0.302546274	0.33815244	0.302546274	0.33815244
β1	0.019534419	0.000397398	49.15583863	3.4382E-90	0.018748742	0.020320096	0.018748742	0.020320096
β2	-0.000140302	4.77487E-06	-29.38344709	9.69188E-62	-0.000149742	-0.000130862	-0.000149742	-0.000130862
β3	3.41163E-07	1.55567E-08	21.9303828	3.96368E-47	3.10407E-07	3.7192E-07	3.10407E-07	3.7192E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994150147
R Square	0.988334515
Adjusted R Square	0.98808454
Standard Error	0.026852947
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.552894405	2.850964802	3953.738464	4.5499E-135
Residual	140	0.100951309	0.000721081		
Total	143	8.653845713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.322462264	0.009024312	35.73261409	3.07114E-72	0.304620715	0.340303814	0.304620715	0.340303814
β1	0.019485751	0.000398256	48.9276546	6.36471E-90	0.018698377	0.020273125	0.018698377	0.020273125
β2	-0.000140187	4.78518E-06	-29.29612329	1.3875E-61	-0.000149648	-0.000130727	-0.000149648	-0.000130727
β3	3.41143E-07	1.55903E-08	21.88177944	5.04366E-47	3.1032E-07	3.71966E-07	3.1032E-07	3.71966E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.99407047
R Square	0.988176099
Adjusted R Square	0.98792273
Standard Error	0.026915882
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.476544403	2.825514801	3900.141282	1.1696E-134
Residual	140	0.101425062	0.000724465		
Total	143	8.577969465			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.324216701	0.009045462	35.84302113	2.08007E-72	0.306333337	0.342100066	0.306333337	0.342100066
β1	0.019446254	0.00039919	48.71430741	1.1346E-89	0.018657034	0.020235473	0.018657034	0.020235473
β2	-0.000140099	4.7964E-06	-29.20929598	1.98384E-61	-0.000149582	-0.000130617	-0.000149582	-0.000130617
β3	3.41157E-07	1.56268E-08	21.8315363	6.47229E-47	3.10262E-07	3.72052E-07	3.10262E-07	3.72052E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994533252
R Square	0.98909639
Adjusted R Square	0.988862741
Standard Error	0.026511278
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.92601569	2.975338563	4233.261276	4.0262E-137
Residual	140	0.098398698	0.000702848		
Total	143	9.024414388			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314154129	0.008909489	35.26062149	1.64245E-71	0.296539591	0.331768668	0.296539591	0.331768668
β1	0.019671366	0.000393189	50.03029541	3.32321E-91	0.01889401	0.020448722	0.01889401	0.020448722
β2	-0.000140565	4.7243E-06	-29.75371308	2.13494E-62	-0.000149906	-0.000131225	-0.000149906	-0.000131225
β3	3.40966E-07	1.53919E-08	22.15229024	1.32417E-47	3.10535E-07	3.71397E-07	3.10535E-07	3.71397E-07

Primary Workover Costs

Primary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Workover costs consist of the total of workover rig services, remedial services, equipment repair and other costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}6)$$

where Cost = WRK_W
$\beta0$ = WRKK
$\beta1$ = WRKA
$\beta2$ = WRKB
$\beta3$ = WRKC
from equation 2-22 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9839
R Square	0.9681
Adjusted R Square	0.9363
Standard Error	1,034.20
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	32,508,694.98	32,508,694.98	30.39	0.11
Residual	1	1,069,571.02	1,069,571.02		
Total	2	33,578,265.99			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,736.081	1,266.632	1.371	0.401	-14,357.935	17,830.097	-14,357.935	17,830.097
β1	1.320	0.239	5.513	0.114	-1.722	4.361	-1.722	4.361

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.7558
R Square	0.5713
Adjusted R Square	0.4284
Standard Error	978.19
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,824,956.55	3,824,956.55	4.00	0.14
Residual	3	2,870,570.06	956,856.69		
Total	4	6,695,526.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,949.479	1,043.913	1.867	0.159	-1,372.720	5,271.678	-1,372.720	5,271.678
β1	0.364	0.182	1.999	0.139	-0.216	0.945	-0.216	0.945

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.9762
R Square	0.9530
Adjusted R Square	0.9060
Standard Error	2,405.79
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	117,342,912.53	117,342,912.53	20.27	0.14
Residual	1	5,787,839.96	5,787,839.96		
Total	2	123,130,752.49			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-2,738.051	2,946.483	-0.929	0.523	-40,176.502	34,700.400	-40,176.502	34,700.400
β1	2.507	0.557	4.503	0.139	-4.568	9.582	-4.568	9.582

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.9898
R Square	0.9798
Adjusted R Square	0.9595
Standard Error	747.71
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	27,074,389.00	27,074,389.00	48.43	0.09
Residual	1	559,069.20	559,069.20		
Total	2	27,633,458.19			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	389.821	915.753	0.426	0.744	-11,245.876	12,025.518	-11,245.876	12,025.518
β1	1.204	0.173	6.959	0.091	-0.995	3.403	-0.995	3.403

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.9985
R Square	0.9969
Adjusted R Square	0.9939
Standard Error	273.2
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	24,387,852.65	24,387,852.65	326.67	0.04
Residual	1	74,656.68	74,656.68		
Total	2	24,462,509.32			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	1,326.648	334.642	3.964	0.157	-2,925.359	5,578.654	-2,925.359	5,578.654
β1	1.143	0.063	18.074	0.035	0.339	1.947	0.339	1.947

Primary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for primary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994400682
R Square	0.988832717
Adjusted R Square	0.988593418
Standard Error	0.02694729
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.001886791	3.00062893	4132.207262	2.1441E-136
Residual	140	0.101661902	0.000726156		
Total	143	9.103548693			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312539579	0.009056017	34.51181296	2.43715E-70	0.294635346	0.330443812	0.294635346	0.330443812
β1	0.019707131	0.000399656	49.31028624	2.26953E-90	0.018916991	0.020497272	0.018916991	0.020497272
β2	-0.000140623	4.802E-06	-29.28428914	1.45673E-61	-0.000150117	-0.000131129	-0.000150117	-0.000131129
β3	3.40873E-07	1.5645E-08	21.78791181	8.03921E-47	3.09942E-07	3.71804E-07	3.09942E-07	3.71804E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994469633
R Square	0.98896985
Adjusted R Square	0.98873349
Standard Error	0.026569939
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.861572267	2.953857422	4184.161269	9.0291E-137
Residual	140	0.098834632	0.000705962		
Total	143	8.960406899			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.315903453	0.008929203	35.37868321	1.07799E-71	0.298249938	0.333556967	0.298249938	0.333556967
β1	0.019629392	0.000394059	49.81332121	5.91373E-91	0.018850316	0.020408468	0.018850316	0.020408468
β2	-0.000140391	4.73475E-06	-29.65123432	3.24065E-62	-0.000149752	-0.00013103	-0.000149752	-0.00013103
β3	3.40702E-07	1.5426E-08	22.08625878	1.83379E-47	3.10204E-07	3.712E-07	3.10204E-07	3.712E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994481853
R Square	0.988994155
Adjusted R Square	0.988758316
Standard Error	0.026752366
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.003736634	3.001245545	4193.504662	7.7373E-137
Residual	140	0.100196473	0.000715689		
Total	143	9.103933107			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312750341	0.00899051	34.78671677	9.00562E-71	0.294975619	0.330525063	0.294975619	0.330525063
β1	0.019699787	0.000396765	49.6510621	9.11345E-91	0.018915362	0.020484212	0.018915362	0.020484212
β2	-0.000140541	4.76726E-06	-29.480463	6.51147E-62	-0.000149966	-0.000131116	-0.000149966	-0.000131116
β3	3.40661E-07	1.55319E-08	21.93302302	3.91217E-47	3.09954E-07	3.71368E-07	3.09954E-07	3.71368E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.949969362
R Square	0.902441789
Adjusted R Square	0.900351256
Standard Error	0.090634678
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.63829925	3.546099748	431.6802228	1.59892E-70
Residual	140	1.150050289	0.008214645		
Total	143	11.78834953			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281549378	0.030459064	9.243533578	3.55063E-16	0.221330174	0.341768582	0.221330174	0.341768582
β1	0.020360006	0.001344204	15.14651492	2.70699E-31	0.017702443	0.02301757	0.017702443	0.02301757
β2	-0.000140998	1.61511E-05	-8.729925387	6.86299E-15	-0.000172929	-0.000109066	-0.000172929	-0.000109066
β3	3.36972E-07	5.26206E-08	6.403797584	2.14112E-09	2.32938E-07	4.41006E-07	2.32938E-07	4.41006E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994382746
R Square	0.988797046
Adjusted R Square	0.988556983
Standard Error	0.026729324
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.828330392	2.942776797	4118.9013	2.6803E-136
Residual	140	0.100023944	0.000714457		
Total	143	8.928354335			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316566704	0.008982767	35.24155917	1.75819E-71	0.298807292	0.334326116	0.298807292	0.334326116
β1	0.019613748	0.000396423	49.47682536	1.45204E-90	0.018829998	0.020397497	0.018829998	0.020397497
β2	-0.000140368	4.76315E-06	-29.46957335	6.80842E-62	-0.000149785	-0.000130951	-0.000149785	-0.000130951
β3	3.40752E-07	1.55185E-08	21.95777375	3.46083E-47	3.10071E-07	3.71433E-07	3.10071E-07	3.71433E-07

Cost to Convert a Primary to Secondary Well

The cost to convert a primary to secondary well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a primary to a secondary well consist of pumping equipment, rods and pumps, and supply wells. The data was analyzed on a regional level. The secondary operations costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}7)$$

where Cost = PSW_W

β0 = PSWK

β1 = PSWA

β2 = PSWB

β3 = PSWC

from equation 2-35 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.999208
R Square	0.998416
Adjusted R Square	0.996832
Standard Error	9968.98
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	62,643,414,406.49	62,643,414,406.49	630.34	0.03
Residual	1	99,380,639.94	99,380,639.94		
Total	2	62,742,795,046.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-115.557	12,209.462	-0.009	0.994	-155,250.815	155,019.701	-155,250.815	155,019.701
β1	57.930	2.307	25.107	0.025	28.612	87.248	28.612	87.248

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.996760
R Square	0.993531
Adjusted R Square	0.991914
Standard Error	16909.05
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	175,651,490,230.16	175,651,490,230.16	614.35	0.00
Residual	4	1,143,664,392.16	285,916,098.04		
Total	5	176,795,154,622.33			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-10,733.7	14,643.670	-0.733	0.504	-51,391.169	29,923.692	-51,391.169	29,923.692
β1	68.593	2.767	24.786	0.000	60.909	76.276	60.909	76.276

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.999830
R Square	0.999660
Adjusted R Square	0.999320
Standard Error	4047.64
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,164,743,341	48,164,743,341	2,939.86	0.01
Residual	1	16,383,350	16,383,350		
Total	2	48,181,126,691			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-32,919.3	4,957.320	-6.641	0.095	-95,907.768	30,069.148	-95,907.768	30,069.148
β1	50.796	0.937	54.220	0.012	38.893	62.700	38.893	62.700

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	1.00000
R Square	0.99999
Adjusted R Square	0.99999
Standard Error	552.23
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	44,056,261,873.48	44,056,261,873.48	144,469.3	0.00
Residual	1	304,952.52	304,952.52		
Total	2	44,056,566,825.99			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-25,175.8	676.335	-37.224	0.017	-33,769.389	-16,582.166	-33,769.389	-16,582.166
β1	48.581	0.128	380.091	0.002	46.957	50.205	46.957	50.205

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.999970
R Square	0.999941
Adjusted R Square	0.999882
Standard Error	2317.03
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	90,641,249,203.56	90,641,249,203.56	16,883.5	0.00
Residual	1	5,368,613.99	5,368,613.99		
Total	2	90,646,617,817.55			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-47,775.5	2,837.767	-16.836	0.038	-83,832.597	-11,718.412	-83,832.597	-11,718.412
β1	69.683	0.536	129.937	0.005	62.869	76.498	62.869	76.498

Cost to Convert a Primary to Secondary Well - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a primary to secondary well was calculated using data through 2008 from the Cost and Indices data base provided EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994210954
R Square	0.988455421
Adjusted R Square	0.988208037
Standard Error	0.032636269
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.7675639	4.255854635	3995.634681	2.1943E-135
Residual	140	0.149117649	0.001065126		
Total	143	12.91668155			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.386844292	0.010967879	35.27065592	1.58464E-71	0.365160206	0.408528378	0.365160206	0.408528378
β1	0.023681158	0.000484029	48.92509151	6.40898E-90	0.022724207	0.024638109	0.022724207	0.024638109
β2	-0.000169861	5.81577E-06	-29.207048	2.00231E-61	-0.00018136	-0.000158363	-0.00018136	-0.000158363
β3	4.12786E-07	1.89479E-08	21.78527316	8.14539E-47	3.75325E-07	4.50247E-07	3.75325E-07	4.50247E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.965088368
R Square	0.931395559
Adjusted R Square	0.929925464
Standard Error	0.077579302
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.43935934	3.813119781	633.5614039	3.21194E-81
Residual	140	0.842596733	0.006018548		
Total	143	12.28195608			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.403458143	0.02607162	15.4749932	4.09637E-32	0.351913151	0.455003136	0.351913151	0.455003136
β1	0.023030837	0.00115058	20.01672737	6.5441E-43	0.02075608	0.025305595	0.02075608	0.025305595
β2	-0.000167719	1.38246E-05	-12.13194348	1.34316E-23	-0.000195051	-0.000140387	-0.000195051	-0.000140387
β3	4.10451E-07	4.5041E-08	9.112847285	7.57277E-16	3.21403E-07	4.995E-07	3.21403E-07	4.995E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.930983781
R Square	0.866730801
Adjusted R Square	0.863875032
Standard Error	0.115716747
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19199867	4.063999556	303.5017657	4.7623E-61
Residual	140	1.874651162	0.013390365		
Total	143	14.06664983			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.39376891	0.038888247	10.12565341	2.02535E-18	0.316884758	0.470653063	0.316884758	0.470653063
β1	0.023409924	0.001716196	13.6405849	1.759E-27	0.020016911	0.026802936	0.020016911	0.026802936
β2	-0.000169013	2.06207E-05	-8.196307608	1.41642E-13	-0.000209782	-0.000128245	-0.000209782	-0.000128245
β3	4.11972E-07	6.71828E-08	6.132113904	8.35519E-09	2.79148E-07	5.44796E-07	2.79148E-07	5.44796E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.930623851
R Square	0.866060752
Adjusted R Square	0.863190626
Standard Error	0.117705607
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.5418858	4.180628599	301.7500036	6.76263E-61
Residual	140	1.939645392	0.01385461		
Total	143	14.48153119			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.363067907	0.039556632	9.178433366	5.17966E-16	0.284862323	0.441273492	0.284862323	0.441273492
β1	0.024133277	0.001745693	13.82446554	5.96478E-28	0.020681947	0.027584606	0.020681947	0.027584606
β2	-0.000175479	2.09751E-05	-8.366057262	5.44112E-14	-0.000216948	-0.00013401	-0.000216948	-0.00013401
β3	4.28328E-07	6.83375E-08	6.267838182	4.24825E-09	2.93221E-07	5.63435E-07	2.93221E-07	5.63435E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.930187107
R Square	0.865248054
Adjusted R Square	0.862360512
Standard Error	0.116469162
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19426209	4.06475403	299.6486777	1.03233E-60
Residual	140	1.899109212	0.013565066		
Total	143	14.0933713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.393797507	0.039141107	10.06097011	2.96602E-18	0.316413437	0.471181577	0.316413437	0.471181577
β1	0.023409194	0.001727356	13.55204156	2.96327E-27	0.01999412	0.026824269	0.01999412	0.026824269
β2	-0.000168995	2.07548E-05	-8.142483197	1.91588E-13	-0.000210029	-0.000127962	-0.000210029	-0.000127962
β3	4.11911E-07	6.76196E-08	6.091589926	1.02095E-08	2.78223E-07	5.45599E-07	2.78223E-07	5.45599E-07

Cost to Convert a Producer to an Injector

The cost to convert a production well to an injection well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a production to an injection well consist of tubing replacement, distribution lines and header costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}8)$$

where Cost = PSI_W
$\beta 0$ = PSIK
$\beta 1$ = PSIA
$\beta 2$ = PSIB
$\beta 3$ = PSIC
from equation 2-36 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994714
R Square	0.989456
Adjusted R Square	0.978913
Standard Error	3204.94
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	963,939,802.16	963,939,802.16	93.84	0.07
Residual	1	10,271,635.04	10,271,635.04		
Total	2	974,211,437.20			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,129.3	3,925.233	2.835	0.216	-38,745.259	61,003.937	-38,745.259	61,003.937
β1	7.186	0.742	9.687	0.065	-2.239	16.611	-2.239	16.611

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.988716
R Square	0.977560
Adjusted R Square	0.971950
Standard Error	4435.41
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,428,080,322.21	3,428,080,322.21	174.25	0.00
Residual	4	78,691,571.93	19,672,892.98		
Total	5	3,506,771,894.14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	24,640.6	3,841.181	6.415	0.003	13,975.763	35,305.462	13,975.763	35,305.462
β1	9.582	0.726	13.201	0.000	7.567	11.598	7.567	11.598

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.993556
R Square	0.987154
Adjusted R Square	0.974307
Standard Error	3770.13
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,092,230,257.01	1,092,230,257.01	76.84	0.07
Residual	1	14,213,917.83	14,213,917.83		
Total	2	1,106,444,174.85			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	9,356.411	4,617.453	2.026	0.292	-49,313.648	68,026.469	-49,313.648	68,026.469
β1	7.649	0.873	8.766	0.072	-3.438	18.737	-3.438	18.737

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995436
R Square	0.990893
Adjusted R Square	0.981785
Standard Error	3266.39
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,160,837,008.65	1,160,837,008.65	108.80	0.06
Residual	1	10,669,310.85	10,669,310.85		
Total	2	1,171,506,319.50			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	24,054.311	4,000.496	6.013	0.105	-26,776.589	74,885.211	-26,776.589	74,885.211
β1	7.886	0.756	10.431	0.061	-1.720	17.492	-1.720	17.492

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.998023
R Square	0.996050
Adjusted R Square	0.992100
Standard Error	2903.09
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,125,305,559.02	2,125,305,559.02	252.17	0.04
Residual	1	8,427,914.12	8,427,914.12		
Total	2	2,133,733,473.15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,125.846	3,555.541	3.129	0.197	-34,051.391	56,303.083	-34,051.391	56,303.083
β1	10.670	0.672	15.880	0.040	2.133	19.208	2.133	19.208

Cost to Convert a Producer to an Injector - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a producer to an injector was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.99432304
R Square	0.988678308
Adjusted R Square	0.9884357
Standard Error	0.026700062
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.715578807	2.905192936	4075.214275	5.6063E-136
Residual	140	0.099805061	0.000712893		
Total	143	8.815383869			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318906241	0.008972933	35.54091476	6.05506E-72	0.301166271	0.336646211	0.301166271	0.336646211
β1	0.019564167	0.000395989	49.40584281	1.75621E-90	0.018781276	0.020347059	0.018781276	0.020347059
β2	-0.000140323	4.75794E-06	-29.49235038	6.20216E-62	-0.00014973	-0.000130916	-0.00014973	-0.000130916
β3	3.40991E-07	1.55015E-08	21.9972576	2.84657E-47	3.10343E-07	3.71638E-07	3.10343E-07	3.71638E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994644466
R Square	0.989317613
Adjusted R Square	0.989088705
Standard Error	0.025871111
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.678119686	2.892706562	4321.895164	9.5896E-138
Residual	140	0.093704013	0.000669314		
Total	143	8.771823699			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316208692	0.008694352	36.36943685	3.2883E-73	0.299019491	0.333397893	0.299019491	0.333397893
β1	0.01974618	0.000383695	51.46325116	7.80746E-93	0.018987594	0.020504765	0.018987594	0.020504765
β2	-0.000142963	4.61022E-06	-31.00997536	1.39298E-64	-0.000152077	-0.000133848	-0.000152077	-0.000133848
β3	3.4991E-07	1.50202E-08	23.29589312	5.12956E-50	3.20214E-07	3.79606E-07	3.20214E-07	3.79606E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994321224
R Square	0.988674696
Adjusted R Square	0.988432011
Standard Error	0.026701262
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.713550392	2.904516797	4073.899599	5.7329E-136
Residual	140	0.099814034	0.000712957		
Total	143	8.813364425			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318954549	0.008973336	35.54470092	5.97425E-72	0.301213782	0.336695317	0.301213782	0.336695317
β1	0.019563077	0.000396007	49.40087012	1.77978E-90	0.018780151	0.020346004	0.018780151	0.020346004
β2	-0.000140319	4.75815E-06	-29.49027089	6.25518E-62	-0.000149726	-0.000130912	-0.000149726	-0.000130912
β3	3.40985E-07	1.55022E-08	21.99592439	2.8654E-47	3.10337E-07	3.71634E-07	3.10337E-07	3.71634E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.994322163
R Square	0.988676564
Adjusted R Square	0.988433919
Standard Error	0.026700311
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.714383869	2.904794623	4074.579587	5.667E-136
Residual	140	0.099806922	0.000712907		
Total	143	8.814190792			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.318944377	0.008973016	35.54483358	5.97144E-72	0.301204242	0.336684512	0.301204242	0.336684512
β1	0.019563226	0.000395993	49.40300666	1.76961E-90	0.018780328	0.020346125	0.018780328	0.020346125
β2	-0.000140317	4.75798E-06	-29.49085218	6.24031E-62	-0.000149724	-0.00013091	-0.000149724	-0.00013091
β3	3.40976E-07	1.55017E-08	21.99610109	2.8629E-47	3.10328E-07	3.71624E-07	3.10328E-07	3.71624E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994041278
R Square	0.988118061
Adjusted R Square	0.987863448
Standard Error	0.027307293
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.681741816	2.893913939	3880.863048	1.6477E-134
Residual	140	0.104396354	0.000745688		
Total	143	8.78613817			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.31978359	0.009177001	34.84619603	7.26644E-71	0.301640166	0.337927015	0.301640166	0.337927015
β1	0.019531533	0.000404995	48.22662865	4.2897E-89	0.018730837	0.02033223	0.018730837	0.02033223
β2	-0.000140299	4.86615E-06	-28.83170535	9.47626E-61	-0.00014992	-0.000130679	-0.00014992	-0.000130679
β3	3.41616E-07	1.58541E-08	21.54755837	2.66581E-46	3.10272E-07	3.7296E-07	3.10272E-07	3.7296E-07

Facilities Upgrade Costs for Crude Oil Wells

The facilities upgrading cost for secondary oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Facilities costs for a secondary oil well consist of plant costs and electrical costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}9)$$

where Cost = FAC_W

$\beta 0$ = FACUPK

$\beta 1$ = FACUPA

$\beta 2$ = FACUPB

$\beta 3$ = FACUPC

from equation 2-23 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.947660
R Square	0.898060
Adjusted R Square	0.796120
Standard Error	6332.38
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	353,260,332.81	353,260,332.81	8.81	0.21
Residual	1	40,099,063.51	40,099,063.51		
Total	2	393,359,396.32			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,711.761	7,755.553	2.671	0.228	-77,831.455	119,254.977	-77,831.455	119,254.977
β1	4.350	1.466	2.968	0.207	-14.273	22.973	-14.273	22.973

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.942744
R Square	0.888767
Adjusted R Square	0.851689
Standard Error	6699.62
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,075,905,796.72	1,075,905,796.72	23.97	0.02
Residual	3	134,654,629.89	44,884,876.63		
Total	4	1,210,560,426.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	33,665.6	7,149.747	4.709	0.018	10,911.921	56,419.338	10,911.921	56,419.338
β1	6.112	1.248	4.896	0.016	2.139	10.085	2.139	10.085

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.950784
R Square	0.903990
Adjusted R Square	0.807980
Standard Error	6705.31
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	423,335,427.35	423,335,427.35	9.42	0.20
Residual	1	44,961,183.70	44,961,183.70		
Total	2	468,296,611.04			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	19,032.550	8,212.294	2.318	0.259	-85,314.094	123,379.194	-85,314.094	123,379.194
β1	4.762	1.552	3.068	0.201	-14.957	24.482	-14.957	24.482

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.90132
R Square	0.81238
Adjusted R Square	0.62476
Standard Error	8,531
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	315,132,483.91	315,132,483.91	4.33	0.29
Residual	1	72,780,134.04	72,780,134.04		
Total	2	387,912,617.95			

	Coefficient	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	37,322	10,448.454	3.572	0.174	-95,437.589	170,081.677	-95,437.589	170,081.677
β1	4.109	1.975	2.081	0.285	-20.980	29.198	-20.980	29.198

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.974616
R Square	0.949876
Adjusted R Square	0.899753
Standard Error	6,765.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	867,401,274.79	867,401,274.79	18.95	0.14
Residual	1	45,771,551.83	45,771,551.83		
Total	2	913,172,826.62			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	23,746.6	8,285.972	2.866	0.214	-81,536.251	129,029.354	-81,536.251	129,029.354
β1	6.817	1.566	4.353	0.144	-13.080	26.713	-13.080	26.713

Facilities Upgrade Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor for facilities upgrade costs for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994217662
R Square	0.988468759
Adjusted R Square	0.988221661
Standard Error	0.026793237
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.615198936	2.871732979	4000.310244	2.0238E-135
Residual	140	0.100502859	0.000717878		
Total	143	8.715701795			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321111529	0.009004246	35.66223488	3.93903E-72	0.303309651	0.338913406	0.303309651	0.338913406
β1	0.019515262	0.000397371	49.11095778	3.88014E-90	0.018729638	0.020300885	0.018729638	0.020300885
β2	-0.00014023	4.77454E-06	-29.37035185	1.02272E-61	-0.00014967	-0.00013079	-0.00014967	-0.00013079
β3	3.4105E-07	1.55556E-08	21.92459665	4.07897E-47	3.10296E-07	3.71805E-07	3.10296E-07	3.71805E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994217643
R Square	0.988468723
Adjusted R Square	0.988221624
Standard Error	0.026793755
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.615504692	2.871834897	4000.297521	2.0242E-135
Residual	140	0.100506746	0.000717905		
Total	143	8.716011438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321091731	0.00900442	35.65934676	3.9795E-72	0.30328951	0.338893953	0.30328951	0.338893953
β1	0.019515756	0.000397379	49.11125155	3.87707E-90	0.018730117	0.020301395	0.018730117	0.020301395
β2	-0.000140234	4.77464E-06	-29.37065243	1.02145E-61	-0.000149674	-0.000130794	-0.000149674	-0.000130794
β3	3.41061E-07	1.55559E-08	21.92486379	4.07357E-47	3.10306E-07	3.71816E-07	3.10306E-07	3.71816E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994881087
R Square	0.989788377
Adjusted R Square	0.989569556
Standard Error	0.025598703
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.892246941	2.964082314	4523.289171	4.0903E-139
Residual	140	0.0917411	0.000655294		
Total	143	8.983988041			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305413562	0.008602806	35.50162345	6.96151E-72	0.288405354	0.32242177	0.288405354	0.32242177
β1	0.019922983	0.000379655	52.47659224	5.82045E-94	0.019172385	0.020673581	0.019172385	0.020673581
β2	-0.000143398	4.56168E-06	-31.43544891	2.62249E-65	-0.000152417	-0.00013438	-0.000152417	-0.00013438
β3	3.48664E-07	1.48621E-08	23.45993713	2.3433E-50	3.1928E-07	3.78047E-07	3.1928E-07	3.78047E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994218671
R Square	0.988470767
Adjusted R Square	0.988223712
Standard Error	0.026793398
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.616820316	2.872273439	4001.015021	1.9993E-135
Residual	140	0.100504067	0.000717886		
Total	143	8.717324383			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32105584	0.0090043	35.65583598	4.02926E-72	0.303253856	0.338857825	0.303253856	0.338857825
β1	0.019516684	0.000397373	49.11424236	3.84594E-90	0.018731056	0.020302312	0.018731056	0.020302312
β2	-0.00014024	4.77457E-06	-29.37236101	1.01431E-61	-0.00014968	-0.000130801	-0.00014968	-0.000130801
β3	3.4108E-07	1.55557E-08	21.92639924	4.0427E-47	3.10326E-07	3.71835E-07	3.10326E-07	3.71835E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994682968
R Square	0.989394207
Adjusted R Square	0.98916694
Standard Error	0.025883453
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.749810675	2.916603558	4353.444193	5.7951E-138
Residual	140	0.093793438	0.000669953		
Total	143	8.843604113			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320979436	0.0086985	36.90055074	5.22609E-74	0.303782034	0.338176837	0.303782034	0.338176837
β1	0.019117244	0.000383878	49.80033838	6.12166E-91	0.018358297	0.019876191	0.018358297	0.019876191
β2	-0.000134273	4.61242E-06	-29.11109331	2.97526E-61	-0.000143392	-0.000125154	-0.000143392	-0.000125154
β3	3.21003E-07	1.50274E-08	21.36117616	6.78747E-46	2.91293E-07	3.50713E-07	2.91293E-07	3.50713E-07

Natural Gas Well Facilities Costs

Natural gas well facilities costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Well facilities costs consist of flowlines and connections, production package costs, and storage tank costs. The data was analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * Q + \beta3 * \text{Depth} * Q \qquad (2.B\text{-}10)$$

where Cost = FWC_W
β0 = FACGK
β1 = FACGA
β2 = FACGB
β3 = FACGC
Q = PEAKDAILY_RATE
from equation 2-28 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9834
R Square	0.9672
Adjusted R Square	0.9562
Standard Error	5,820.26
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8,982,542,532.41	2,994,180,844.14	88.39	0.00
Residual	9	304,879,039.45	33,875,448.83		
Total	12	9,287,421,571.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,477.41	4,694.03	0.74	0.48	-7,141.24	14,096.05	-7,141.24	14,096.05
β1	5.04	0.40	12.51	0.00	4.13	5.95	4.13	5.95
β2	63.87	19.07	3.35	0.01	20.72	107.02	20.72	107.02
β3	0.00	0.00	-3.18	0.01	-0.01	0.00	-0.01	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9621
R Square	0.9256
Adjusted R Square	0.9139
Standard Error	8,279.60
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	16,213,052,116.02	5,404,350,705.34	78.84	0.00
Residual	19	1,302,484,315.70	68,551,806.09		
Total	22	17,515,536,431.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	14,960.60	4,066.98	3.68	0.00	6,448.31	23,472.90	6,448.31	23,472.90
β1	4.87	0.47	10.34	0.00	3.88	5.85	3.88	5.85
β2	28.49	6.42	4.43	0.00	15.04	41.93	15.04	41.93
β3	0.00	0.00	-3.62	0.00	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.9917
R Square	0.9835
Adjusted R Square	0.9765
Standard Error	4,030.43
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6,796,663,629.62	2,265,554,543.21	139.47	0.00
Residual	7	113,710,456.60	16,244,350.94		
Total	10	6,910,374,086.22			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,185.92	3,441.41	2.96	0.02	2,048.29	18,323.54	2,048.29	18,323.54
β1	4.51	0.29	15.71	0.00	3.83	5.18	3.83	5.18
β2	55.38	14.05	3.94	0.01	22.16	88.60	22.16	88.60
β3	0.00	0.00	-3.78	0.01	-0.01	0.00	-0.01	0.00

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9594
R Square	0.9204
Adjusted R Square	0.8806
Standard Error	7,894.95
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4,322,988,996.06	1,440,996,332.02	23.12	0.00
Residual	6	373,981,660.54	62,330,276.76		
Total	9	4,696,970,656.60			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,922.48	8,200.06	0.97	0.37	-12,142.36	27,987.31	-12,142.36	27,987.31
β1	6.51	1.14	5.71	0.00	3.72	9.30	3.72	9.30
β2	89.26	28.88	3.09	0.02	18.59	159.94	18.59	159.94
β3	-0.01	0.00	-2.77	0.03	-0.01	0.00	-0.01	0.00

Gas Well Facilities Costs - Cost Adjustment Factor

The cost adjustment factor for gas well facilities cost was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Gas Price} + \beta2 * \text{Gas Price}^2 + \beta3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995733794
R Square	0.991485789
Adjusted R Square	0.991303341
Standard Error	0.025214281
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.3648558	3.454951933	5434.365566	1.2179E-144
Residual	140	0.089006392	0.00063576		
Total	143	10.45386219			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.276309237	0.008473615	32.60818851	2.86747E-67	0.259556445	0.293062029	0.259556445	0.293062029
β1	0.20599743	0.003739533	55.08640551	8.89871E-97	0.198604173	0.213390688	0.198604173	0.213390688
β2	-0.014457925	0.000449317	-32.17753015	1.48375E-66	-0.015346249	-0.0135696	-0.015346249	-0.0135696
β3	0.000347281	1.46389E-05	23.72318475	6.71084E-51	0.000318339	0.000376223	0.000318339	0.000376223

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.99551629
R Square	0.991052684
Adjusted R Square	0.990860956
Standard Error	0.025683748
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.22936837	3.409789455	5169.05027	3.9254E-143
Residual	140	0.092351689	0.000659655		
Total	143	10.32172006			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.280854163	0.008631386	32.5387085	3.73403E-67	0.263789449	0.297918878	0.263789449	0.297918878
β1	0.204879431	0.00380916	53.78599024	2.17161E-95	0.197348518	0.212410345	0.197348518	0.212410345
β2	-0.014391989	0.000457683	-31.44530093	2.52353E-65	-0.015296854	-0.013487125	-0.015296854	-0.013487125
β3	0.000345909	1.49115E-05	23.19753012	8.21832E-50	0.000316428	0.00037539	0.000316428	0.00037539

Mid-Continent, Applied to OLOGSS Regions 3 and 6:

Regression Statistics	
Multiple R	0.995511275
R Square	0.991042698
Adjusted R Square	0.990850756
Standard Error	0.025690919
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.22356717	3.407855722	5163.235345	4.2442E-143
Residual	140	0.092403264	0.000660023		
Total	143	10.31597043			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.280965064	0.008633796	32.5424714	3.68097E-67	0.263895586	0.298034543	0.263895586	0.298034543
β1	0.204856879	0.003810223	53.7650588	2.28751E-95	0.197323863	0.212389895	0.197323863	0.212389895
β2	-0.014391983	0.000457811	-31.43650889	2.61165E-65	-0.0152971	-0.013486865	-0.0152971	-0.013486865
β3	0.000345929	1.49156E-05	23.19242282	8.42221E-50	0.00031644	0.000375418	0.00031644	0.000375418

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995452965
R Square	0.990926606
Adjusted R Square	0.990732176
Standard Error	0.025768075
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.15228252	3.384094173	5096.576002	1.0453E-142
Residual	140	0.092959113	0.000663994		
Total	143	10.24524163			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.282511839	0.008659725	32.62364879	2.704E-67	0.265391097	0.299632581	0.265391097	0.299632581
β1	0.204502598	0.003821666	53.51137044	4.3021E-95	0.196946958	0.212058237	0.196946958	0.212058237
β2	-0.014382652	0.000459186	-31.32206064	4.08566E-65	-0.015290487	-0.013474816	-0.015290487	-0.013474816
β3	0.000345898	1.49604E-05	23.12086258	1.18766E-49	0.00031632	0.000375475	0.00031632	0.000375475

Fixed Annual Costs for Crude Oil Wells

The fixed annual cost for crude oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of supervision and overhead costs, auto usage costs, operative supplies, labor costs, supplies and services costs, equipment usage and other costs.

The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}11)$$

where Cost = OMO_W
$\beta 0$ = OMOK
$\beta 1$ = OMOA
$\beta 2$ = OMOB
$\beta 3$ = OMOC
from equation 2-30 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9895
R Square	0.9792
Adjusted R Square	0.9584
Standard Error	165.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,290,021.8	1,290,021.8	47.0	0.1
Residual	1	27,419.5	27,419.5		
Total	2	1,317,441.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,026.949	202.804	29.718	0.021	3,450.097	8,603.802	3,450.097	8,603.802
β1	0.263	0.038	6.859	0.092	-0.224	0.750	-0.224	0.750

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8631
R Square	0.7449
Adjusted R Square	0.6811
Standard Error	2,759.2
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	88,902,026.9	88,902,026.9	11.7	0.0
Residual	4	30,452,068.1	7,613,017.0		
Total	5	119,354,095.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,171.358	2,389.511	3.001	0.040	536.998	13,805.718	536.998	13,805.718
β1	1.543	0.452	3.417	0.027	0.289	2.797	0.289	2.797

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9888
R Square	0.9777
Adjusted R Square	0.9554
Standard Error	325.8
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4,654,650.4	4,654,650.4	43.9	0.1
Residual	1	106,147.3	106,147.3		
Total	2	4,760,797.7			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,572.283	399.025	13.965	0.046	502.211	10,642.355	502.211	10,642.355
β1	0.499	0.075	6.622	0.095	-0.459	1.458	-0.459	1.458

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9634
R Square	0.9282
Adjusted R Square	0.8923
Standard Error	455.6
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5,368,949.5	5,368,949.5	25.9	0.0
Residual	2	415,138.5	207,569.2		
Total	3	5,784,088.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,327.733	447.809	14.130	0.005	4,400.964	8,254.501	4,400.964	8,254.501
β1	0.302	0.059	5.086	0.037	0.046	0.557	0.046	0.557

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9908
R Square	0.9817
Adjusted R Square	0.9725
Standard Error	313.1
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	10,498,366.6	10,498,366.6	107.1	0.0
Residual	2	196,056.3	98,028.2		
Total	3	10,694,422.9			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,193.399	307.742	16.876	0.003	3,869.291	6,517.508	3,869.291	6,517.508
β1	0.422	0.041	10.349	0.009	0.246	0.597	0.246	0.597

Fixed Annual Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994014283
R Square	0.988064394
Adjusted R Square	0.987808631
Standard Error	0.026960479
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.424110153	2.808036718	3863.203308	2.2587E-134
Residual	140	0.101761442	0.000726867		
Total	143	8.525871595			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325522735	0.00906045	35.9278779	1.54278E-72	0.30760974	0.343435731	0.30760974	0.343435731
β1	0.019415379	0.000399851	48.55651174	1.74247E-89	0.018624852	0.020205906	0.018624852	0.020205906
β2	-0.000139999	4.80435E-06	-29.14014276	2.63883E-61	-0.000149498	-0.000130501	-0.000149498	-0.000130501
β3	3.41059E-07	1.56527E-08	21.78917295	7.98896E-47	3.10113E-07	3.72006E-07	3.10113E-07	3.72006E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.972995979
R Square	0.946721175
Adjusted R Square	0.945579485
Standard Error	0.052710031
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.91165462	2.303884873	829.2285185	6.67464E-89
Residual	140	0.388968632	0.002778347		
Total	143	7.300623252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305890757	0.01771395	17.26835352	1.6689E-36	0.270869326	0.340912188	0.270869326	0.340912188
β1	0.019637228	0.000781743	25.11979642	1.01374E-53	0.01809168	0.021182776	0.01809168	0.021182776
β2	-0.000147609	9.39291E-06	-15.71490525	1.03843E-32	-0.000166179	-0.000129038	-0.000166179	-0.000129038
β3	3.60127E-07	3.06024E-08	11.76795581	1.17387E-22	2.99625E-07	4.2063E-07	2.99625E-07	4.2063E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.993998856
R Square	0.988033725
Adjusted R Square	0.987777305
Standard Error	0.02698784
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.419321124	2.806440375	3853.182417	2.7032E-134
Residual	140	0.10196809	0.000728344		
Total	143	8.521289214			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32545185	0.009069645	35.88363815	1.80273E-72	0.307520675	0.343383025	0.307520675	0.343383025
β1	0.019419103	0.000400257	48.51658921	1.94263E-89	0.018627774	0.020210433	0.018627774	0.020210433
β2	-0.000140059	4.80922E-06	-29.12303298	2.83205E-61	-0.000149567	-0.000130551	-0.000149567	-0.000130551
β3	3.41232E-07	1.56686E-08	21.77807458	8.44228E-47	3.10254E-07	3.72209E-07	3.10254E-07	3.72209E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.977862049
R Square	0.956214186
Adjusted R Square	0.955275919
Standard Error	0.050111949
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.677722068	2.559240689	1019.127536	7.26235E-95
Residual	140	0.351569047	0.002511207		
Total	143	8.029291115			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.343679311	0.016840828	20.40750634	8.67459E-44	0.310384089	0.376974533	0.310384089	0.376974533
β1	0.020087054	0.000743211	27.02739293	2.04852E-57	0.018617686	0.021556422	0.018617686	0.021556422
β2	-0.000153877	8.92993E-06	-17.23164844	2.04504E-36	-0.000171532	-0.000136222	-0.000171532	-0.000136222
β3	3.91397E-07	2.9094E-08	13.45286338	5.31787E-27	3.33877E-07	4.48918E-07	3.33877E-07	4.48918E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993729589
R Square	0.987498496
Adjusted R Square	0.987230606
Standard Error	0.027203598
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.183798235	2.727932745	3686.217436	5.7808E-133
Residual	140	0.103605007	0.000740036		
Total	143	8.287403242			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.330961672	0.009142153	36.20171926	5.90451E-73	0.312887144	0.3490362	0.312887144	0.3490362
β1	0.019295414	0.000403457	47.82521879	1.29343E-88	0.018497758	0.02009307	0.018497758	0.02009307
β2	-0.000139784	4.84767E-06	-28.83529781	9.33567E-61	-0.000149368	-0.0001302	-0.000149368	-0.0001302
β3	3.4128E-07	1.57939E-08	21.60840729	1.96666E-46	3.10055E-07	3.72505E-07	3.10055E-07	3.72505E-07

Fixed Annual Costs for Natural Gas Wells

Fixed annual costs for natural gas wells were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of the lease equipment costs for natural gas production for a given year. The data was analyzed on a regional level. The independent variables are depth and Q which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * Q + \beta 3 * \text{Depth} * Q \tag{2.B-12}$$

where Cost = FOAMG_W
$\beta 0$ = OMGK
$\beta 1$ = OMGA
$\beta 2$ = OMGB
$\beta 3$ = OMGC
Q = PEAKDAILY_RATE
from equation 2-29 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.928
R Square	0.861
Adjusted R Square	0.815
Standard Error	6,471.68
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,344,632,468.49	781,544,156.16	18.66	0.00
Residual	9	376,944,241.62	41,882,693.51		
Total	12	2,721,576,710.11			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,450.28	5,219.40	0.85	0.42	-7,356.84	16,257.40	-7,356.84	16,257.40
β1	2.50	0.45	5.58	0.00	1.49	3.51	1.49	3.51
β2	27.65	21.21	1.30	0.22	-20.33	75.63	-20.33	75.63
β3	0.00	0.00	-1.21	0.26	0.00	0.00	0.00	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.913
R Square	0.834
Adjusted R Square	0.807
Standard Error	6,564.36
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4,100,685,576.61	1,366,895,192.20	31.72	0.00
Residual	19	818,725,806.73	43,090,831.93		
Total	22	4,919,411,383.34			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,145.70	3,224.45	3.46	0.00	4,396.85	17,894.55	4,396.85	17,894.55
β1	2.68	0.37	7.17	0.00	1.90	3.46	1.90	3.46
β2	7.67	5.09	1.51	0.15	-2.99	18.33	-2.99	18.33
β3	0.00	0.00	-1.21	0.24	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS region 3 and 6:

Regression Statistics	
Multiple R	0.934
R Square	0.873
Adjusted R Square	0.830
Standard Error	6,466.88
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,578,736,610.45	859,578,870.15	20.55	0.00
Residual	9	376,384,484.71	41,820,498.30		
Total	12	2,955,121,095.16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	8,193.82	5,410.04	1.51	0.16	-4,044.54	20,432.18	-4,044.54	20,432.18
β1	2.75	0.45	6.14	0.00	1.74	3.77	1.74	3.77
β2	21.21	18.04	1.18	0.27	-19.59	62.01	-19.59	62.01
β3	0.00	0.00	-1.12	0.29	0.00	0.00	0.00	0.00

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.945
R Square	0.893
Adjusted R Square	0.840
Standard Error	6,104.84
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	1,874,387,985.75	624,795,995.25	16.76	0.00
Residual	6	223,614,591.98	37,269,098.66		
Total	9	2,098,002,577.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,534.86	6,340.77	1.19	0.28	-7,980.45	23,050.17	-7,980.45	23,050.17
β1	3.81	0.88	4.33	0.00	1.66	5.97	1.66	5.97
β2	32.27	22.33	1.44	0.20	-22.38	86.92	-22.38	86.92
β3	0.00	0.00	-1.18	0.28	-0.01	0.00	-0.01	0.00

Fixed Annual Costs for Gas Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for gas wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$1 to \$20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Gas Price} + \beta 2 * \text{Gas Price}^2 + \beta 3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994836789
R Square	0.989700237
Adjusted R Square	0.989479527
Standard Error	0.029019958
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.32916798	3.776389326	4484.181718	7.4647E-139
Residual	140	0.117902114	0.000842158		
Total	143	11.44707009			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.234219858	0.009752567	24.01622716	1.68475E-51	0.21493851	0.253501206	0.21493851	0.253501206
β1	0.216761767	0.004303953	50.36340872	1.37772E-91	0.20825262	0.225270914	0.20825262	0.225270914
β2	-0.015234638	0.000517134	-29.45972427	7.08872E-62	-0.01625704	-0.014212235	-0.01625704	-0.014212235
β3	0.000365319	1.68484E-05	21.68270506	1.3574E-46	0.000332009	0.000398629	0.000332009	0.000398629

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.995657421
R Square	0.991333701
Adjusted R Square	0.991147994
Standard Error	0.02551118
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.42258156	3.474193854	5338.176859	4.2055E-144
Residual	140	0.091114842	0.00065082		
Total	143	10.5136964			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.276966489	0.008573392	32.30535588	9.09319E-67	0.260016432	0.293916546	0.260016432	0.293916546
β1	0.205740933	0.003783566	54.37751691	5.03408E-96	0.198260619	0.213221246	0.198260619	0.213221246
β2	-0.014407802	0.000454608	-31.6927929	9.63037E-66	-0.015306587	-0.013509017	-0.015306587	-0.013509017
β3	0.00034576	1.48113E-05	23.34441529	4.06714E-50	0.000316478	0.000375043	0.000316478	0.000375043

Mid-Continent, Applied to OLOGSS Region 3 and 6:

Regression Statistics	
Multiple R	0.995590124
R Square	0.991199695
Adjusted R Square	0.991011117
Standard Error	0.025596313
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.33109303	3.443697678	5256.179662	1.231E-143
Residual	140	0.091723972	0.000655171		
Total	143	10.42281701			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.278704883	0.008602002	32.40000063	6.33409E-67	0.261698262	0.295711504	0.261698262	0.295711504
β1	0.205373482	0.003796192	54.09986358	9.97995E-96	0.197868206	0.212878758	0.197868206	0.212878758
β2	-0.014404563	0.000456125	-31.58028284	1.49116E-65	-0.015306347	-0.013502779	-0.015306347	-0.013502779
β3	0.000345945	1.48607E-05	23.27919988	5.55628E-50	0.000316565	0.000375325	0.000316565	0.000375325

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995548929
R Square	0.99111767
Adjusted R Square	0.990927334
Standard Error	0.02564864
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.27673171	3.425577238	5207.209824	2.3566E-143
Residual	140	0.092099383	0.000657853		
Total	143	10.3688311			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.279731342	0.008619588	32.45298388	5.17523E-67	0.262689954	0.296772729	0.262689954	0.296772729
β1	0.205151971	0.003803953	53.93125949	1.51455E-95	0.197631352	0.21267259	0.197631352	0.21267259
β2	-0.014402579	0.000457058	-31.51151347	1.94912E-65	-0.015306207	-0.013498952	-0.015306207	-0.013498952
β3	0.00034606	1.48911E-05	23.23943141	6.72233E-50	0.00031662	0.000375501	0.00031662	0.000375501

Fixed Annual Costs for Secondary Production

The fixed annual cost for secondary oil production was calculated an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}13)$$

where Cost = OPSEC_W
β0 = OPSECK
β1 = OPSECA
β2 = OPSECB
β3 = OPSECC
from equation 2-31 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9972
R Square	0.9945
Adjusted R Square	0.9890
Standard Error	1,969.67
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	698,746,493.71	698,746,493.71	180.11	0.05
Residual	1	3,879,582.16	3,879,582.16		
Total	2	702,626,075.87			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	30,509.3	2,412.338	12.647	0.050	-142.224	61,160.827	-142.224	61,160.827
β1	6.118	0.456	13.420	0.047	0.326	11.911	0.326	11.911

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.935260
R Square	0.874710
Adjusted R Square	0.843388
Standard Error	8414.07
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,977,068,663.41	1,977,068,663.41	27.93	0.01
Residual	4	283,186,316.21	70,796,579.05		
Total	5	2,260,254,979.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	55,732.7	7,286.799	7.648	0.002	35,501.310	75,964.186	35,501.310	75,964.186
β1	7.277	1.377	5.285	0.006	3.454	11.101	3.454	11.101

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.998942
R Square	0.997884
Adjusted R Square	0.995768
Standard Error	1329.04
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	833,049,989.02	833,049,989.02	471.62	0.03
Residual	1	1,766,354.45	1,766,354.45		
Total	2	834,816,343.47			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	28,208.7	1,627.738	17.330	0.037	7,526.417	48,890.989	7,526.417	48,890.989
β1	6.680	0.308	21.717	0.029	2.772	10.589	2.772	10.589

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.989924
R Square	0.979949
Adjusted R Square	0.959899
Standard Error	3639.10
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	647,242,187.96	647,242,187.96	48.87	0.09
Residual	1	13,243,073.43	13,243,073.43		
Total	2	660,485,261.39			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	53,857.06	4,456.973	12.084	0.053	-2,773.909	110,488.034	-2,773.909	110,488.034
β1	5.888	0.842	6.991	0.090	-4.814	16.591	-4.814	16.591

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.992089
R Square	0.984240
Adjusted R Square	0.968480
Standard Error	5193.40
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,684,438,248.88	1,684,438,248.88	62.45	0.08
Residual	1	26,971,430.96	26,971,430.96		
Total	2	1,711,409,679.84			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	35,893.465	6,360.593	5.643	0.112	-44,925.189	116,712.119	-44,925.189	116,712.119
β1	9.499	1.202	7.903	0.080	-5.774	24.773	-5.774	24.773

Fixed Annual Costs for Secondary Production - Cost Adjustment Factor

The cost adjustment factor of the fixed annual costs for secondary production was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994022382
R Square	0.988080495
Adjusted R Square	0.987825078
Standard Error	0.026956819
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.433336986	2.811112329	3868.484883	2.0551E-134
Residual	140	0.101733815	0.00072667		
Total	143	8.535070802			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325311813	0.00905922	35.90947329	1.646E-72	0.307401249	0.343222377	0.307401249	0.343222377
β1	0.019419982	0.000399797	48.57461816	1.65866E-89	0.018629562	0.020210402	0.018629562	0.020210402
β2	-0.000140009	4.80369E-06	-29.14604996	2.57525E-61	-0.000149506	-0.000130512	-0.000149506	-0.000130512
β3	3.41057E-07	1.56506E-08	21.79195958	7.87903E-47	3.10115E-07	3.71999E-07	3.10115E-07	3.71999E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.993830992
R Square	0.987700041
Adjusted R Square	0.987436471
Standard Error	0.027165964
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.296590955	2.765530318	3747.383987	1.8532E-133
Residual	140	0.103318541	0.00073799		
Total	143	8.399909496			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321750317	0.009129506	35.24290662	1.74974E-71	0.303700794	0.33979984	0.303700794	0.33979984
β1	0.019369439	0.000402899	48.0752057	6.49862E-89	0.018572887	0.020165992	0.018572887	0.020165992
β2	-0.000140208	4.84096E-06	-28.96291516	5.49447E-61	-0.000149779	-0.000130638	-0.000149779	-0.000130638
β3	3.42483E-07	1.5772E-08	21.71459435	1.15795E-46	3.11301E-07	3.73665E-07	3.11301E-07	3.73665E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994021683
R Square	0.988079106
Adjusted R Square	0.987823658
Standard Error	0.026959706
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.43414809	2.811382697	3868.028528	2.0719E-134
Residual	140	0.101755604	0.000726826		
Total	143	8.535903693			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325281756	0.00906019	35.90231108	1.68802E-72	0.307369274	0.343194238	0.307369274	0.343194238
β1	0.019420568	0.00039984	48.57088177	1.67561E-89	0.018630063	0.020211072	0.018630063	0.020211072
β2	-0.000140009	4.80421E-06	-29.14305099	2.60734E-61	-0.000149507	-0.000130511	-0.000149507	-0.000130511
β3	3.41049E-07	1.56523E-08	21.7891193	7.99109E-47	3.10103E-07	3.71994E-07	3.10103E-07	3.71994E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994023418
R Square	0.988082555
Adjusted R Square	0.987827181
Standard Error	0.026956158
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.434398087	2.811466029	3869.161392	2.0304E-134
Residual	140	0.101728825	0.000726634		
Total	143	8.536126912			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325293493	0.009058998	35.90833165	1.65262E-72	0.307383368	0.343203618	0.307383368	0.343203618
β1	0.019420405	0.000399787	48.57686713	1.64854E-89	0.018630005	0.020210806	0.018630005	0.020210806
β2	-0.000140009	4.80358E-06	-29.14672886	2.56804E-61	-0.000149505	-0.000130512	-0.000149505	-0.000130512
β3	3.41053E-07	1.56502E-08	21.792237	7.86817E-47	3.10111E-07	3.71994E-07	3.10111E-07	3.71994E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993899019
R Square	0.98783526
Adjusted R Square	0.987574587
Standard Error	0.027222624
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.42499532	2.808331773	3789.557133	8.5487E-134
Residual	140	0.103749972	0.000741071		
Total	143	8.528745292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.327122709	0.009148547	35.75679345	2.81971E-72	0.30903554	0.345209878	0.30903554	0.345209878
β1	0.019283711	0.000403739	47.76280844	1.53668E-88	0.018485497	0.020081925	0.018485497	0.020081925
β2	-0.000138419	4.85106E-06	-28.53379985	3.28809E-60	-0.00014801	-0.000128828	-0.00014801	-0.000128828
β3	3.36276E-07	1.58049E-08	21.27670912	1.03818E-45	3.05029E-07	3.67523E-07	3.05029E-07	3.67523E-07

Lifting Costs

Lifting costs for crude oil wells were calculated using average an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Lifting costs consist of labor costs for the pumper, chemicals, fuel, power and water costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}14)$$

where Cost = OML_W
β0 = OMLK
β1 = OMLA
β2 = OMLB
β3 = OMLC
from equation 2-32 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9994
R Square	0.9988
Adjusted R Square	0.9976
Standard Error	136.7
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	15,852,301	15,852,301	849	0
Residual	1	18,681	18,681		
Total	2	15,870,982			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,534.515	167.395	45.010	0.014	5,407.565	9,661.465	5,407.565	9,661.465
β1	0.922	0.032	29.131	0.022	0.520	1.323	0.520	1.323

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8546
R Square	0.7304
Adjusted R Square	0.6764
Standard Error	2263.5
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	69,387,339	69,387,339	14	0
Residual	5	25,617,128	5,123,426		
Total	6	95,004,467			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,585.191	1,654.440	7.002	0.001	7,332.324	15,838.058	7,332.324	15,838.058
β1	0.912	0.248	3.680	0.014	0.275	1.549	0.275	1.549

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9997
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	82.0
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	13,261,874	13,261,874	1,972	0
Residual	1	6,726	6,726		
Total	2	13,268,601			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	8,298.339	100.447	82.614	0.008	7,022.045	9,574.634	7,022.045	9,574.634
β1	0.843	0.019	44.403	0.014	0.602	1.084	0.602	1.084

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	1.0000
R Square	1.0000
Adjusted R Square	0.9999
Standard Error	11.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,979,238	3,979,238	30,138	0
Residual	1	132	132		
Total	2	3,979,370			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,137.398	14.073	720.342	0.001	9,958.584	10,316.212	9,958.584	10,316.212
β1	0.462	0.003	173.603	0.004	0.428	0.495	0.428	0.495

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9969
R Square	0.9937
Adjusted R Square	0.9874
Standard Error	1134.3
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	203,349,853	203,349,853	158	0
Residual	1	1,286,583	1,286,583		
Total	2	204,636,436			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,147.313	1,389.199	3.705	0.168	-12,504.063	22,798.689	-12,504.063	22,798.689
β1	3.301	0.263	12.572	0.051	-0.035	6.636	-0.035	6.636

Lifting Costs - Cost Adjustment Factor

The cost adjustment factor for lifting costs for was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994419415
R Square	0.988869972
Adjusted R Square	0.988631472
Standard Error	0.026749137
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.900010642	2.966670214	4146.195026	1.6969E-136
Residual	140	0.100172285	0.000715516		
Total	143	9.000182927			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314447949	0.008989425	34.97976138	4.49274E-71	0.296675373	0.332220525	0.296675373	0.332220525
β1	0.019667961	0.000396717	49.57683267	1.11119E-90	0.018883631	0.020452291	0.018883631	0.020452291
β2	-0.000140635	4.76668E-06	-29.50377541	5.91881E-62	-0.000150059	-0.000131211	-0.000150059	-0.000131211
β3	3.41221E-07	1.553E-08	21.97170644	3.23018E-47	3.10517E-07	3.71924E-07	3.10517E-07	3.71924E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994725637
R Square	0.989479094
Adjusted R Square	0.989253646
Standard Error	0.026400955
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.177423888	3.059141296	4388.946164	3.302E-138
Residual	140	0.097581462	0.00069701		
Total	143	9.275005349			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307250046	0.008872414	34.62981435	1.58839E-70	0.289708807	0.324791284	0.289708807	0.324791284
β1	0.019843369	0.000391553	50.6786443	6.01683E-92	0.019069248	0.020617491	0.019069248	0.020617491
β2	-0.000141338	4.70464E-06	-30.04217841	6.6318E-63	-0.000150639	-0.000132036	-0.000150639	-0.000132036
β3	3.42235E-07	1.53279E-08	22.32765206	5.59173E-48	3.11931E-07	3.72539E-07	3.11931E-07	3.72539E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994625665
R Square	0.989280214
Adjusted R Square	0.989050504
Standard Error	0.026521235
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.087590035	3.029196678	4306.653909	1.2247E-137
Residual	140	0.09847263	0.000703376		
Total	143	9.186062664			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309274775	0.008912836	34.69993005	1.23231E-70	0.291653621	0.32689593	0.291653621	0.32689593
β1	0.019797213	0.000393337	50.33145871	1.49879E-91	0.019019565	0.020574861	0.019019565	0.020574861
β2	-0.000141221	4.72607E-06	-29.88132995	1.27149E-62	-0.000150565	-0.000131878	-0.000150565	-0.000131878
β3	3.42202E-07	1.53977E-08	22.22423366	9.29272E-48	3.1176E-07	3.72644E-07	3.1176E-07	3.72644E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994686146
R Square	0.98940053
Adjusted R Square	0.989173398
Standard Error	0.026467032
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.154328871	3.051442957	4356.069182	5.5581E-138
Residual	140	0.09807053	0.000700504		
Total	143	9.252399401			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307664081	0.00889462	34.58990756	1.8356E-70	0.29007894	0.325249222	0.29007894	0.325249222
β1	0.019836272	0.000392533	50.53404116	8.79346E-92	0.019060214	0.020612331	0.019060214	0.020612331
β2	-0.000141357	4.71641E-06	-29.97123684	8.83426E-63	-0.000150681	-0.000132032	-0.000150681	-0.000132032
β3	3.42352E-07	1.53662E-08	22.27954719	7.08083E-48	3.11973E-07	3.72732E-07	3.11973E-07	3.72732E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993880162
R Square	0.987797777
Adjusted R Square	0.987536301
Standard Error	0.027114753
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.332367897	2.777455966	3777.77319	1.0603E-133
Residual	140	0.102929375	0.00073521		
Total	143	8.435297272			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.326854136	0.009112296	35.86957101	1.8943E-72	0.308838638	0.344869634	0.308838638	0.344869634
β1	0.019394839	0.000402139	48.22916512	4.26E-89	0.018599788	0.02018989	0.018599788	0.02018989
β2	-0.000140183	4.83184E-06	-29.01231258	4.47722E-61	-0.000149736	-0.00013063	-0.000149736	-0.00013063
β3	3.41846E-07	1.57423E-08	21.71513554	1.15483E-46	3.10722E-07	3.72969E-07	3.10722E-07	3.72969E-07

Secondary Workover Costs

Secondary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Secondary workover costs consist of workover rig services, remedial services and equipment repair. The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}15)$$

where Cost = SWK_W

$\beta 0$ = OMSWRK

$\beta 1$ = OMSWRA

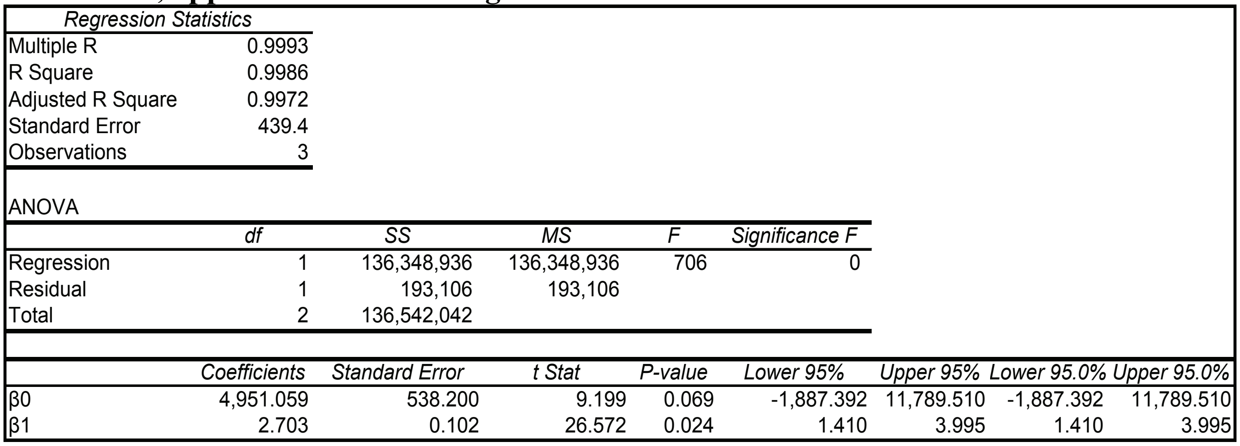
$\beta 2$ = OMSWRB

$\beta 3$ = OMSWRC

from equation 2-33 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:



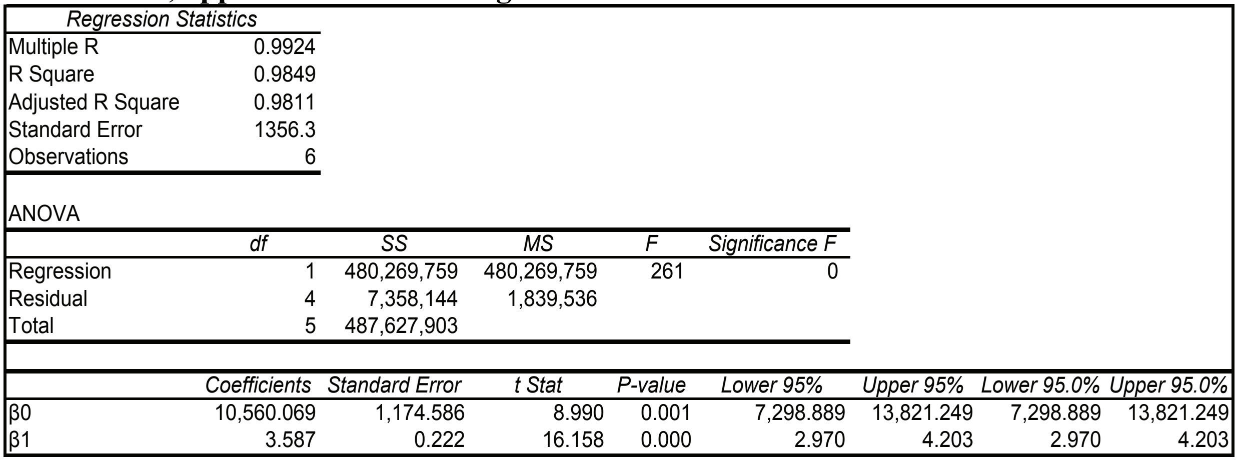
Regression Statistics	
Multiple R	0.9993
R Square	0.9986
Adjusted R Square	0.9972
Standard Error	439.4
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	136,348,936	136,348,936	706	0
Residual	1	193,106	193,106		
Total	2	136,542,042			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,951.059	538.200	9.199	0.069	-1,887.392	11,789.510	-1,887.392	11,789.510
β1	2.703	0.102	26.572	0.024	1.410	3.995	1.410	3.995

South Texas, applied to OLOGSS region 2:



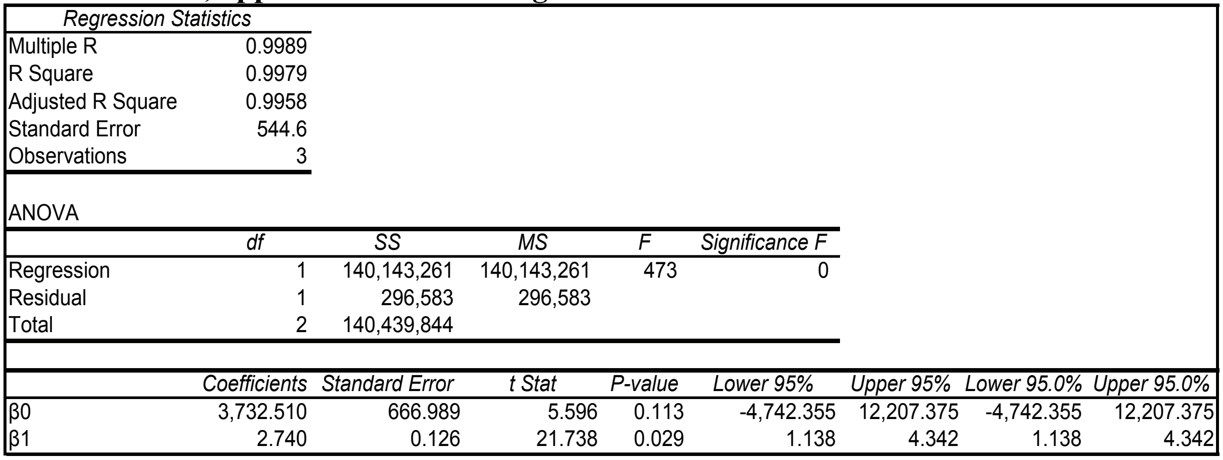
Regression Statistics	
Multiple R	0.9924
R Square	0.9849
Adjusted R Square	0.9811
Standard Error	1356.3
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	480,269,759	480,269,759	261	0
Residual	4	7,358,144	1,839,536		
Total	5	487,627,903			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,560.069	1,174.586	8.990	0.001	7,298.889	13,821.249	7,298.889	13,821.249
β1	3.587	0.222	16.158	0.000	2.970	4.203	2.970	4.203

Mid-Continent, applied to OLOGSS region 3:



Regression Statistics	
Multiple R	0.9989
R Square	0.9979
Adjusted R Square	0.9958
Standard Error	544.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	140,143,261	140,143,261	473	0
Residual	1	296,583	296,583		
Total	2	140,439,844			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,732.510	666.989	5.596	0.113	-4,742.355	12,207.375	-4,742.355	12,207.375
β1	2.740	0.126	21.738	0.029	1.138	4.342	1.138	4.342

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9983
Standard Error	290.9
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	98,740,186	98,740,186	1,167	0
Residual	1	84,627	84,627		
Total	2	98,824,812			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,291.954	356.287	14.853	0.043	764.922	9,818.987	764.922	9,818.987
β1	2.300	0.067	34.158	0.019	1.444	3.155	1.444	3.155

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9991
R Square	0.9983
Adjusted R Square	0.9966
Standard Error	454.7
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	120,919,119	120,919,119	585	0
Residual	1	206,762	206,762		
Total	2	121,125,881			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,131.486	556.905	7.419	0.085	-2,944.638	11,207.610	-2,944.638	11,207.610
β1	2.545	0.105	24.183	0.026	1.208	3.882	1.208	3.882

Secondary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for secondary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994646805
R Square	0.989322267
Adjusted R Square	0.989093459
Standard Error	0.026416612
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.051925882	3.017308627	4323.799147	9.3015E-138
Residual	140	0.097697232	0.000697837		
Total	143	9.149623114			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312179978	0.008877675	35.1646082	2.31513E-71	0.294628337	0.329731619	0.294628337	0.329731619
β1	0.019705242	0.000391785	50.29605017	1.64552E-91	0.018930662	0.020479822	0.018930662	0.020479822
β2	-0.000140397	4.70743E-06	-29.82464336	1.6003E-62	-0.000149704	-0.000131091	-0.000149704	-0.000131091
β3	3.4013E-07	1.53369E-08	22.17714344	1.1716E-47	3.09808E-07	3.70452E-07	3.09808E-07	3.70452E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994648271
R Square	0.989325182
Adjusted R Square	0.989096436
Standard Error	0.026409288
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.049404415	3.016468138	4324.992582	9.1255E-138
Residual	140	0.097643067	0.00069745		
Total	143	9.147047482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31224985	0.008875214	35.18223288	2.17363E-71	0.294703075	0.329796624	0.294703075	0.329796624
β1	0.019703773	0.000391676	50.30624812	1.60183E-91	0.018929408	0.020478139	0.018929408	0.020478139
β2	-0.000140393	4.70612E-06	-29.83187838	1.55398E-62	-0.000149697	-0.000131088	-0.000149697	-0.000131088
β3	3.40125E-07	1.53327E-08	22.18299399	1.13834E-47	3.09811E-07	3.70439E-07	3.09811E-07	3.70439E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994391906
R Square	0.988815263
Adjusted R Square	0.98857559
Standard Error	0.027366799
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.269694355	3.089898118	4125.685804	2.3918E-136
Residual	140	0.104851837	0.000748942		
Total	143	9.374546192			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.301399555	0.009196999	32.7715099	1.54408E-67	0.283216594	0.319582517	0.283216594	0.319582517
β1	0.020285999	0.000405877	49.980617	3.79125E-91	0.019483558	0.021088441	0.019483558	0.021088441
β2	-0.000145269	4.87675E-06	-29.78803686	1.85687E-62	-0.00015491	-0.000135627	-0.00015491	-0.000135627
β3	3.51144E-07	1.58886E-08	22.10035946	1.71054E-47	3.19731E-07	3.82556E-07	3.19731E-07	3.82556E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994645783
R Square	0.989320233
Adjusted R Square	0.989091381
Standard Error	0.026422924
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.054508298	3.018169433	4322.966602	9.4264E-138
Residual	140	0.097743924	0.000698171		
Total	143	9.152252223			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312146343	0.008879797	35.15242029	2.41837E-71	0.294590508	0.329702178	0.294590508	0.329702178
β1	0.019706241	0.000391879	50.28658391	1.68714E-91	0.018931476	0.020481006	0.018931476	0.020481006
β2	-0.000140397	4.70855E-06	-29.81743751	1.64782E-62	-0.000149706	-0.000131088	-0.000149706	-0.000131088
β3	3.4012E-07	1.53406E-08	22.17121727	1.20629E-47	3.09791E-07	3.70449E-07	3.09791E-07	3.70449E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994644139
R Square	0.989316964
Adjusted R Square	0.989088042
Standard Error	0.026428705
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.05566979	3.018556597	4321.629647	9.6305E-138
Residual	140	0.097786705	0.000698476		
Total	143	9.153456495			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312123671	0.00888174	35.14217734	2.50872E-71	0.294563994	0.329683347	0.294563994	0.329683347
β1	0.019707015	0.000391964	50.27755672	1.72782E-91	0.01893208	0.020481949	0.01893208	0.020481949
β2	-0.0001404	4.70958E-06	-29.81159891	1.68736E-62	-0.000149711	-0.000131089	-0.000149711	-0.000131089
β3	3.40124E-07	1.5344E-08	22.16666321	1.23366E-47	3.09789E-07	3.7046E-07	3.09789E-07	3.7046E-07

Additional Cost Equations and Factors

The model uses several updated cost equations and factors originally developed for DOE/NETL's Comprehensive Oil and Gas Analysis Model (COGAM). These are:

- The crude oil and natural gas investment factors for tangible and intangible investments as well as the operating costs. These factors were originally developed based upon the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.
- The G&A factors for capitalized and expensed costs.
- The limits on impurities, such as N2, CO2, and H2S used to calculate natural gas processing costs.
- Cost equations for stimulation, the produced water handling plant, the chemical handling plant, the polymer handling plant, CO_2 recycling plant, and the steam manifolds and pipelines.

Natural and Industrial CO2 Prices

The model uses regional CO_2 prices for both natural and industrial sources of CO_2. The cost equation for natural CO_2 is derived from the equation used in COGAM and updated to reflect current dollar values. According to University of Wyoming, this equation is applicable to the natural CO_2 in the Permian basin (Southwest). The cost of CO_2 in other regions and states is calculated using state calibration factors which represent the additional cost of transportation.

The industrial CO_2 costs contain two components: cost of capture and cost of transportation. The capture costs are derived using data obtained from Denbury Resources, Inc. and other sources. CO_2 capture costs range between \$20 and \$63/ton. The transportation costs were derived using an external economic model which calculates pipeline tariff based upon average distance, compression rate, and volume of CO_2 transported.

National Crude Oil Drilling Footage Equation

The equation for crude oil drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Oil Footage} = \beta 0 + \beta 1 * \text{Oil Price} \tag{2.B-16}$$

where $\beta 0$ = OILA0
$\beta 1$ = OILA1
from equation 2-99 in Chapter 2.

Oil footage is the footage of total developmental crude oil wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of crude oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Oil Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9623
R Square	0.9259
Adjusted R Square	0.9167
Standard Error	5,108.20
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,609,812,096.02	2,609,812,096.02	100.02	0.00
Residual	8	208,749,712.88	26,093,714.11		
Total	9	2,818,561,808.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,984.11	4,377.97	0.91	0.39	-6,111.51	14,079.72	-6,111.51	14,079.72
β1	1,282.45	128.23	10.00	0.00	986.74	1,578.16	986.74	1,578.16

Regional Crude Oil Footage Distribution

The regional drilling distributions for crude oil were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Oil
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.6%
Gulf Coast	AL,FL,LA,MS,TX	29.3%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	18.3%
Rocky Mountains	CO,NV,UT,WY,NM	10.7%
West Coast	CA,WA	9.6%
Northern Great Plains	MT,ND,SD	7.6%

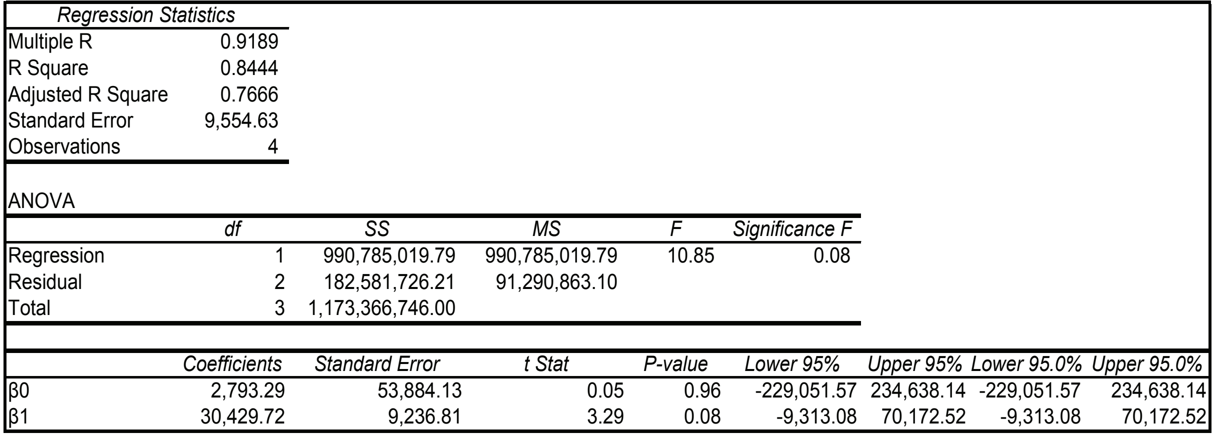
National Natural Gas Drilling Footage Equation

The equation for natural gas drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

Gas Footage = β0 + β1 * Gas Price (2.B-17)
where β0 = GASA0
β1 = GASA1
from equation 2-100 in Chapter 2.

Gas footage is footage of total developmental natural gas wells drilled in the United States in thousands of feet. The gas price is a rolling five year average of natural gas prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Gas Footage
Current sample: (1999 to 2008)



Regression Statistics	
Multiple R	0.9189
R Square	0.8444
Adjusted R Square	0.7666
Standard Error	9,554.63
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	990,785,019.79	990,785,019.79	10.85	0.08
Residual	2	182,581,726.21	91,290,863.10		
Total	3	1,173,366,746.00			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	2,793.29	53,884.13	0.05	0.96	-229,051.57	234,638.14	-229,051.57	234,638.14
β1	30,429.72	9,236.81	3.29	0.08	-9,313.08	70,172.52	-9,313.08	70,172.52

Regional Natural Gas Footage Distribution

The regional drilling distributions for natural gas were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Gas
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	13.2%
Gulf Coast	AL,FL,LA,MS,TX	18.7%
Midcontinent	AR,KS,MO,NE,OK,TX	13.4%
Southwest	TX,NM	34.5%
Rocky Mountains	CO,NV,UT,WY,NM	19.5%
West Coast	CA,WA	0.4%
Northern Great Plains	MT,ND,SD	0.4%

National Exploration Drilling Footage Equation

The equation for exploration well drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Exploration Footage} = \beta 0 + \beta 1 * \text{Oil Price} \qquad (2.B\text{-}18)$$

where $\beta 0 = EXPA0$
$\beta 1 = EXPA1$

Exploration footage is footage of total exploratory crude oil, natural gas and dry wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Exploration Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9467
R Square	0.8963
Adjusted R Square	0.8834
Standard Error	2,825.10
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	552,044,623.08	552,044,623.08	69.17	0.00
Residual	8	63,849,573.82	7,981,196.73		
Total	9	615,894,196.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,733.91	2,421.24	1.96	0.09	-849.49	10,317.31	-849.49	10,317.31
β1	589.83	70.92	8.32	0.00	426.28	753.37	426.28	753.37

Regional Exploration Footage Distribution

The regional distribution for drilled exploration projects is also estimated using the updated EIA well count file. The percent allocations for each corresponding region are calculated using a 2004 – 2008 average of footage drilled for exploratory fields for both crude oil and natural gas.

Region Name	States Included	Exploration
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	22.3%
Gulf Coast	AL,FL,LA,MS,TX	9.0%
Midcontinent	AR,KS,MO,NE,OK,TX	28.8%
Southwest	TX,NM	14.3%
Rocky Mountains	CO,NV,UT,WY,NM	11.5%
West Coast	CA,WA	0.3%
Northern Great Plains	MT,ND,SD	13.8%

Regional Dryhole Rate for Discovered Projects

The percent allocation for existing regional dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Existing dryhole rates calculate the projects which have already been discovered. The formula for the percentage is given below:

Existing Dryhole Rate = Developed Dryhole / Total Drilling (2.B-19)

Region Name	States Included	Existing
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	5.8%
Gulf Coast	AL,FL,LA,MS,TX	9.4%
Midcontinent	AR,KS,MO,NE,OK,TX	13.2%
Southwest	TX,NM	9.7%
Rocky Mountains	CO,NV,UT,WY,NM	4.3%
West Coast	CA,WA	1.5%
Northern Great Plains	MT,ND,SD	5.2%

Regional Dryhole Rate for First Exploration Well Drilled

The percent allocation for undiscovered regional exploration dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each region. Undiscovered regional exploration dryhole rates calculate the rate for the first well drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Exploration = Exploration Dryhole / (Exploration Gas + Exploration Oil)

Region Name	States Included	Undisc. Exp
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	30.8%
Gulf Coast	AL,FL,LA,MS,TX	167.8%
Midcontinent	AR,KS,MO,NE,OK,TX	76.4%
Southwest	TX,NM	86.2%
Rocky Mountains	CO,NV,UT,WY,NM	74.0%
West Coast	CA,WA	466.0%
Northern Great Plains	MT,ND,SD	46.9%

Regional Dryhole Rate for Subsequent Exploration Wells Drilled

The percent allocation for undiscovered regional developed dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Undiscovered regional developed dryhole rates calculate the rate for subsequent wells drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Developed = (Developed Dryhole + Explored Dryhole) / Total Drilling (2.B-20)

Region Name	States Included	Undisc. Dev
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.3%
Gulf Coast	AL,FL,LA,MS,TX	11.6%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	10.8%
Rocky Mountains	CO,NV,UT,WY,NM	6.5%
West Coast	CA,WA	1.8%
Northern Great Plains	MT,ND,SD	10.5%

National Rig Depth Rating

The national rig depth rating schedule was calculated using a three year average based on the Smith Rig Count as reported by *Oil and Gas Journal*. Percentages are applied to determine the cumulative available rigs for drilling.

Appendix 2.C: Play-level Resource Assumptions for Tight Gas, Shale Gas, and Coalbed Methane

The detailed resource assumptions underlying the estimates of remaining unproved technically recoverable resources for tight gas, shale gas, and coalbed methane are presented in the following tables.

Table 2.C-1. Remaining Technically Recoverable Resources (TRR) – Tight Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Berea Sandstone	51863	8	4000	0.18	0%	11401
1	Appalachian	Clinton/Medina High	14773	8	5900	0.25	0%	6786
1	Appalachian	Clinton/Medina Moderate/Low	27281	15	5200	0.08	0%	16136
1	Appalachian	Tuscarora Sandstone	42495	8	8000	0.69	0%	1485
1	Appalachian	Upper Devonian High	12775	10	4600	0.21	0%	10493
1	Appalachian	Upper Devonian Moderate/Low	29808	10	5400	0.06	0%	5492
2	East Texas	Cotton Valley/Bossier	2730	12	12500	1.39	0%	36447
2	Texas-Gulf	Olmos	2500	4	5000	0.44	0%	3624
2	Texas-Gulf	Vicksburg	600	8	11000	2.36	0%	4875
2	Texas-Gulf	Wilcox/Lobo	1500	8	9500	1.60	0%	8532
3	Anadarko	Cherokee/Redfork	1500	4	8500	0.90	0%	1168
3	Anadarko	Cleveland	1500	4	6500	0.91	0%	3690
3	Anadarko	Granite Wash/Atoka	1500	4	13000	1.72	0%	6871
3	Arkoma	Arkoma Basin	1000	8	8000	1.30	0%	2281
4	Permian	Abo	1500	8	3800	1.00	0%	9158
4	Permian	Canyon	6000	8	4500	0.22	0%	11535
5	Denver	Denver/Jules	3500	16	4999	0.24	1%	12953
5	Greater Green River	Deep Mesaverde	16416	4	15100	0.41	8%	2939
5	Greater Green River	Fort Union/Fox Hills	3858	8	5000	0.70	12%	1062
5	Greater Green River	Frontier (Deep)	15619	4	17000	2.58	9%	11303
5	Greater Green River	Frontier (Moxa Arch)	2334	8	9500	1.20	15%	3414
5	Greater Green River	Lance	5500	8	10000	6.60	11%	31541
5	Greater Green River	Lewis	5172	8	9500	1.32	6%	18893
5	Greater Green River	Shallow Mesaverde (1)	5239	4	9750	1.25	8%	12606
5	Greater Green River	Shallow Mesaverde (2)	6814	8	10500	0.67	8%	17874
5	Piceance	Iles/Mesaverde	972	8	8000	0.73	5%	1858
5	Piceance	North Williams Fork/Mesaverde	1008	8	8000	0.65	2%	4278
5	Piceance	South Williams Fork/Mesaverde	1008	32	7000	0.65	9%	22402
5	San Juan	Central Basin/Dakota	3918	6	6500	0.49	7%	15007
5	San Juan	Central Basin/Mesaverde	3689	8	4500	0.72	2%	8737
5	San Juan	Picture Cliffs	6558	4	3500	0.48	2%	4899
5	Uinta	Basin Flank Mesaverde	1708	8	8000	0.99	33%	5767
5	Uinta	Deep Synclinal Mesaverde	2893	8	18000	0.99	2%	3292
5	Uinta	Tertiary East	1600	16	6000	0.58	16%	5910
5	Uinta	Tertiary West	1603	8	6500	4.06	57%	10630
5	Williston	High Potential	2000	4	2300	0.61	4%	2960
5	Williston	Low Potential	3000	4	2500	0.21	1%	1886
5	Williston	Moderate Potential	2000	4	2300	0.33	4%	2071
5	Wind River	Fort Union/Lance Deep	2500	4	14500	0.54	9%	4261
5	Wind River	Fort Union/Lance Shallow	1500	8	11000	1.17	0%	13197
5	Wind River	Mesaverde/Frontier Deep	250	4	17000	1.99	9%	1221
5	Wind River	Mesaverde/Frontier Shallow	250	4	13500	1.25	0%	1037
6	Columbia	Basin Centered	1500	8	13100	1.26	0%	7508

Table 2.C-2. Remaining Technically Recoverable Resources (TRR) – Shale Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Cincinatti Arch	6000	4	1800	0.12	0%	1435
1	Appalachian	Devonian Big Sandy - Active	8675	8	3800	0.32	0%	6490
1	Appalachian	Devonian Big Sandy - Undeveloped	1994	8	3800	0.32	0%	940
1	Appalachian	Devonian Greater Siltstone Area	22914	11	2911	0.20	0%	8463
1	Appalachian	Devonian Low Thermal Maturity	45844	7	3000	0.30	0%	13534
1	Appalachian	Marcellus - Active	10622	8	6750	3.49	0%	177931
1	Appalachian	Marcellus - Undeveloped	84271	8	6750	1.15	0%	232443
1	Illinois	New Albany	1600	8	2750	1.09	0%	10947
1	Michigan	Antrim	12000	7	1400	0.28	0%	20512
2	Black Warrior	Floyd-Neal/Conasauga	2429	2	8000	0.92	0%	4465
2	TX-LA-MS Salt	Haynesville - Active	3574	8	12000	6.48	0%	60615
2	TX-LA-MS Salt	Haynesville - Undeveloped	5426	8	12000	1.50	0%	19408
2	West Gulf Coast	Eagle Ford - Dry	200	4	7000	5.50	0%	4378
2	West Gulf Coast	Eagle Ford - Wet	890	8	7000	2.31	0%	16429
3	Anadarko	Cana Woodford	688	4	13500	3.42	0%	5718
3	Anadarko	Woodford - Central Oklahoma	1800	4	5000	1.01	0%	2946
3	Arkoma	Fayetteville - Central	4000	8	4000	2.29	0%	29505
3	Arkoma	Fayetteville - West	5000	8	4000	1.17	0%	4639
3	Arkoma	Woodford - Western Arkoma	2900	4	9500	4.06	0%	19771
4	Fort Worth	Barnett - Fort Worth Active	2649	5	7500	1.60	0%	15834
4	Fort Worth	Barnett - Fort Worth Undeveloped	477	8	7500	1.20	0%	4094
4	Permian	Barnett - Permian Active	1426	5	7500	1.60	0%	19871
4	Permian	Barnett - Permian Undeveloped	1906	8	7500	1.20	0%	15823
4	Permian	Barnett-Woodford	2691	4	10200	2.99	0%	32152
5	Greater Green River	Hilliard-Baxter-Mancos	16416	8	14750	0.18	0%	3770
5	San Juan	Lewis	7506	3	4500	1.53	0%	11638
5	Uinta	Mancos	6589	8	15250	1.00	0%	21021
5	Williston	Shallow Niobrara	10000	2	1000	0.46	4%	6757

Table 2.C-3. Remaining Technically Recoverable Resources (TRR) – Coalbed Methane

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Central Basin	3870	8	1900	0.18	0%	1709
1	Appalachian	North Appalachia - High	3817	12	1400	0.12	0%	532
1	Appalachian	North Appalachia - Mod/Low	8906	12	1800	0.08	0%	469
1	Illinois	Central Basin	1214	8	1000	0.12	0%	1161
2	Black Warrior	Extention Area	700	8	1900	0.08	0%	931
2	Black Warrior	Main Area	1000	12	1950	0.21	0%	2190
2	Cahaba	Cahaba Coal Field	387	8	3000	0.18	0%	379
3	Midcontinent	Arkoma	2998	8	1500	0.22	0%	3032
3	Midcontinent	Cherokee & Forest City	2750	8	1000	0.06	0%	1308
4	Raton	Southern	386	8	2000	0.37	2%	962
5	Greater Green River	Deep	3600	4	7000	0.60	15%	3879
5	Greater Green River	Shallow	720	8	1500	0.20	20%	1053
5	Piceance	Deep	2000	4	7000	0.60	3%	3677
5	Piceance	Divide Creek	144	8	3800	0.18	13%	194
5	Piceance	Shallow	2000	4	3500	0.30	9%	2230
5	Piceance	White River Dome	216	8	7500	0.41	8%	657
5	Powder River	Big George/Lower Fort Union	2880	16	1100	0.26	1%	5943
5	Powder River	Wasatch	216	8	1100	0.06	1%	92
5	Powder River	Wyodak/Upper Fort Union	3600	20	600	0.14	1%	18859
5	Raton	Northern	470	8	2500	0.35	0%	957
5	Raton	Purgatoire River	360	8	2000	0.31	0%	430
5	San Juan	Fairway NM	670	4	3250	1.14	7%	774
5	San Juan	North Basin	2060	4	3000	0.28	7%	1511
5	San Juan	North Basin CO	780	4	2800	1.51	7%	10474
5	San Juan	South Basin	1190	4	2000	0.20	7%	820
5	San Juan	South Menefee NM	7454	5	2500	0.10	7%	177
5	Uinta	Blackhawk	586	8	3250	0.16	5%	1864
5	Uinta	Ferron	400	8	3000	0.78	11%	1409
5	Uinta	Sego	534	4	3250	0.31	10%	417

3. Offshore Oil and Gas Supply Submodule

Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service's (MMS) 2006 hydrocarbon resource assessment.[1] MMS was renamed Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in 2010.

- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas by 2009. The production volumes are from the BOEMRE production database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters. The crosswalk between region and evaluation unit is shown in Table 3-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is projected in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on BOEMRE's latest[1] resource assessment (Table 3-2). The volume of resource in barrels of oil equivalence by field size class as defined by the BOEMRE is shown in Table 3-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. Fields smaller than field size class 2 are assumed to be uneconomic to develop.

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[1] U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources*, February 2006.

Table 3-1. Offshore Region and Evaluation Unit Crosswalk

No.	Region Name	Planning Area	Water Depth (meters)	Drilling Depth (feet)	Evaluation Unit Name	Region ID
1	Shallow GOM	Western GOM	0 - 200	< 15,000	WGOM0002	3
2	Shallow GOM	Western GOM	0 - 200	> 15,000	WGOMDG02	3
3	Deep GOM	Western GOM	201 - 400	All	WGOM0204	4
4	Deep GOM	Western GOM	401 - 800	All	WGOM0408	4
5	Deep GOM	Western GOM	801 - 1,600	All	WGOM0816	4
6	Deep GOM	Western GOM	1,601 - 2,400	All	WGOM1624	4
7	Deep GOM	Western GOM	> 2,400	All	WGOM2400	4
8	Shallow GOM	Central GOM	0 - 200	< 15,000	CGOM0002	3
9	Shallow GOM	Central GOM	0 - 200	> 15,000	CGOMDG02	3
10	Deep GOM	Central GOM	201 - 400	All	CGOM0204	4
11	Deep GOM	Central GOM	401 - 800	All	CGOM0408	4
12	Deep GOM	Central GOM	801 - 1,600	All	CGOM0816	4
13	Deep GOM	Central GOM	1,601 – 2,400	All	CGOM1624	4
14	Deep GOM	Central GOM	> 2,400	All	CGOM2400	4
15	Shallow GOM	Eastern GOM	0 - 200	All	EGOM0002	3
16	Deep GOM	Eastern GOM	201 - 400	All	EGOM0204	4
17	Deep GOM	Central GOM	401 - 800	All	EGOM0408	4
18	Deep GOM	Eastern GOM	801 - 1600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1601 - 2400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2400	All	EGOM2400	4
21	Deep GOM	Eastern GOM	> 200	All	EGOML181	4
22	Atlantic	North Atlantic	0 - 200	All	NATL0002	1
23	Atlantic	North Atlantic	201 - 800	All	NATL0208	1
24	Atlantic	North Atlantic	> 800	All	NATL0800	1
25	Atlantic	Mid Atlantic	0 - 200	All	MATL0002	1
26	Atlantic	Mid Atlantic	201 - 800	All	MATL0208	1
27	Atlantic	Mid Atlantic	> 800	All	MATL0800	1
28	Atlantic	South Atlantic	0 - 200	All	SATL0002	1
29	Atlantic	South Atlantic	201 - 800	All	SATL0208	1
30	Atlantic	South Atlantic	> 800	All	SATL0800	1
31	Atlantic	Florida Straits	0 – 200	All	FLST0002	1
32	Atlantic	Florida Straits	201 - 800	All	FLST0208	1
33	Atlantic	Florida Straits	> 800	All	FLST0800	1
34	Pacific	Pacific Northwest	0-200	All	PNW0002	2
35	Pacific	Pacific Northwest	201-800	All	PNW0208	2
36	Pacific	North California	0-200	All	NCA0002	2
37	Pacific	North California	201-800	All	NCA0208	2
38	Pacific	North California	801-1600	All	NCA0816	2
39	Pacific	North California	1600-2400	All	NCA1624	2
40	Pacific	Central California	0-200	All	CCA0002	2
41	Pacific	Central California	201-800	All	CCA0208	2
42	Pacific	Central California	801-1600	All	CCA0816	2
43	Pacific	South California	0-200	All	SCA0002	2
44	Pacific	South California	201-800	All	SCA0208	2
45	Pacific	South California	801-1600	All	SCA0816	2
46	Pacific	South California	1601-2400	All	SCA1624	2

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003

Evaluation Unit	Field Size Class (FSC)																Number of Fields	Total Resource (BBOE)
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
WGOM0002	1	5	11	14	20	23	24	27	30	8	6	8	2	0	0	0	179	4.348
WGOMDG02	0	0	2	4	5	6	8	9	9	3	2	2	1	0	0	0	51	1.435
WGOM0204	0	0	0	0	0	0	2	3	3	4	2	1	1	0	0	0	16	1.027
WGOM0408	0	0	0	0	0	1	3	3	7	7	3	2	1	0	0	0	27	1.533
WGOM0816	0	0	0	0	0	0	4	7	16	16	15	9	3	2	1	0	73	8.082
WGOM1624	0	0	0	1	2	6	10	14	18	18	14	10	6	4	1	0	104	10.945
WGOM2400	0	0	0	0	2	3	3	6	7	6	5	3	3	2	0	0	40	4.017
CGOM0002	1	1	6	11	28	52	79	103	81	53	20	1	0	0	0	0	436	8.063
CGOMDG02	0	0	1	1	4	4	4	6	7	6	5	3	1	0	0	0	42	3.406
CGOM0204	0	0	0	0	0	0	1	2	3	2	2	2	1	0	0	0	13	1.102
CGOM0408	0	0	0	0	0	1	1	4	4	4	1	1	1	1	0	0	18	1.660
CGOM0816	0	0	0	0	2	4	8	11	20	22	19	14	7	3	1	0	111	11.973
CGOM1624	0	0	0	1	2	5	9	15	18	19	15	13	8	4	1	0	110	12.371
CGOM2400	0	0	0	0	2	2	3	5	5	5	5	4	3	2	0	0	36	4.094
EGOM0002	4	6	7	11	16	18	18	16	13	10	6	1	0	0	0	0	126	1.843
EGOM0204	0	1	1	2	3	4	4	3	1	1	1	0	0	0	0	0	21	0.233
EGOM0408	0	1	2	3	5	5	5	4	3	2	1	0	0	0	0	0	31	0.348
EGOM0816	0	1	1	3	4	4	4	3	3	2	1	0	0	0	0	0	26	0.326
EGOM1624	0	0	0	0	2	1	1	1	0	1	0	1	0	0	0	0	7	0.250
EGOM2400	0	0	0	1	1	3	5	7	8	9	7	6	3	2	0	0	52	4.922
EGOML181	0	0	0	0	1	3	3	5	8	5	4	2	2	1	1	0	35	1.836
NATL0002	5	7	10	14	16	17	15	11	10	8	3	2	1	0	0	0	119	1.896
NATL0208	1	1	1	2	2	3	3	3	2	1	1	0	0	0	0	0	20	0.246
NATL0800	1	2	3	5	7	10	13	12	7	6	4	1	0	0	0	0	71	1.229
MATL0002	4	6	8	12	13	14	13	11	8	7	5	2	0	0	0	0	103	1.585
MATL0208	1	1	2	3	3	3	3	4	2	2	2	2	0	0	0	0	28	0.377
MATL0800	2	4	5	8	9	10	10	8	5	5	3	2	0	0	0	0	71	1.173
SATL0002	1	2	2	3	5	6	5	5	4	4	1	1	0	0	0	0	39	0.658
SATL0208	4	5	7	10	12	13	12	10	8	7	3	2	0	0	0	0	93	1.382
SATL0800	2	2	4	5	9	15	20	17	11	7	2	1	1	0	0	0	96	1.854
FLST0002	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0.012
FLST0208	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0.009
FLST0800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
PNW0002	10	17	24	29	27	21	13	8	5	2	1	0	0	0	0	0	157	0.597
PNW0208	4	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	59	0.209
NCA0002	1	2	3	5	5	5	5	4	3	3	2	0	0	0	0	0	38	0.485
NCA0208	9	17	24	28	26	22	15	10	5	3	1	1	0	0	0	0	161	0.859
NCA0816	3	6	9	12	12	11	9	7	4	3	2	1	0	0	0	0	79	0.784
NCA1624	1	2	3	5	6	6	7	6	4	2	1	1	0	0	0	0	44	0.595
CCA0002	1	4	6	11	15	19	20	17	12	8	4	2	0	0	0	0	119	1.758
CCA0208	1	2	3	5	8	10	10	8	7	5	2	0	0	0	0	0	61	0.761
CCA0816	0	1	1	2	3	4	5	3	2	2	0	0	0	0	0	0	23	0.218
SCA0002	1	2	4	10	16	21	22	19	12	6	2	1	0	0	0	0	116	1.348
SCA0208	3	6	12	25	38	49	51	43	28	14	5	3	1	0	0	0	278	3.655
SCA0816	1	3	6	9	13	17	18	15	12	8	2	2	1	0	0	0	107	1.906
SCA1624	0	1	2	3	4	5	5	5	4	3	1	1	0	0	0	0	34	0.608

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-3. BOEMRE Field Size Definition (MMBOE)

Field Size Class	Mean
2	0.083
3	0.188
4	0.356
5	0.743
6	1.412
7	2.892
8	5.919
9	11.624
10	22.922
11	44.768
12	89.314
13	182.144
14	371.727
15	690.571
16	1418.883
17	2954.129

Source: Bureau of Ocean Energy Management, Regulation, and Enforcement

Projection of Discoveries

The number and size of discoveries is projected based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

$$\text{DiscoveredFields}_{\text{EU,iFSC}} = \text{TotalFields}_{\text{EU,iFSC}} * (1 - e^{\gamma_{\text{EU,iFSC}} * \text{CumNFW}_{\text{EU}}}) \qquad (3\text{-}1)$$

where,

TotalFields = Total number of fields by evaluation unit and field size class
CumNFW = Cumulative new field wildcats drilled in an evaluation unit
γ = search coefficient
EU = evaluation unit
iFSC = field size class.

The search coefficient (γ) was chosen to make the Equation 3-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates of the search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to obtain enough data points to provide a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. The polynomial was fit to the resulting search coefficients as follows:

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[2] Arps, J. J. and T. G. Roberts, *Economics of Drilling for Cretaceous Oil on the East Flank of the Denver-Julesburg Basin*, Bulletin of the American Association of Petroleum Geologists, November 1958.

$$\gamma_{\mathrm{EU,iFSC}} = \beta 1 * \mathrm{iFSC}^2 + \beta 2 * \mathrm{iFSC} + \beta 3 * \gamma_{\mathrm{EU,10}} \qquad (3\text{-}2)$$

where

$\beta 1$ = 0.0243 for Western GOM and 0.0399 for Central and Eastern GOM
$\beta 2$ = -0.3525 for Western GOM and -0.6222 for Central and Eastern GOM
$\beta 3$ = 1.5326 for Western GOM and 2.2477 for Central and 3.0477 for Eastern GOM
iFSC = field size class
γ = search coefficient for field size class 10.

Cumulative new field wildcat drilling is determined by

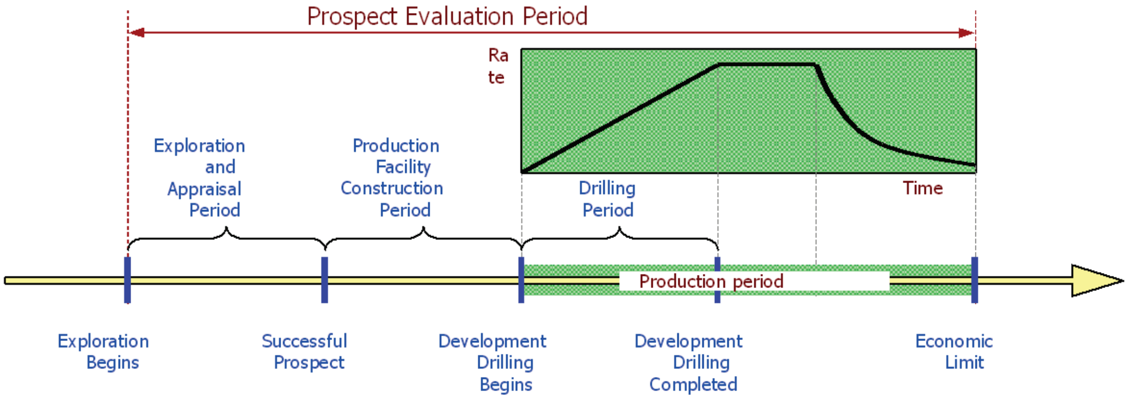
$$\mathrm{CumNFW}_{\mathrm{EU,t}} = \mathrm{CumNFW}_{\mathrm{EU,t-1}} + \alpha 1_{\mathrm{EU}} + \beta_{\mathrm{EU}} * (\mathrm{OILPRICE}_{\mathrm{t-nlag1}} * \mathrm{GASPRICE}_{\mathrm{t-nlag2}}) \qquad (3\text{-}3)$$

where

OILPRICE = oil wellhead price
GASPRICE = natural gas wellhead price
$\alpha 1, \beta$ = estimated parameter
nlag1 = number of years lagged for oil price
nlag2 = number of years lagged for gas price
EU = evaluation unit

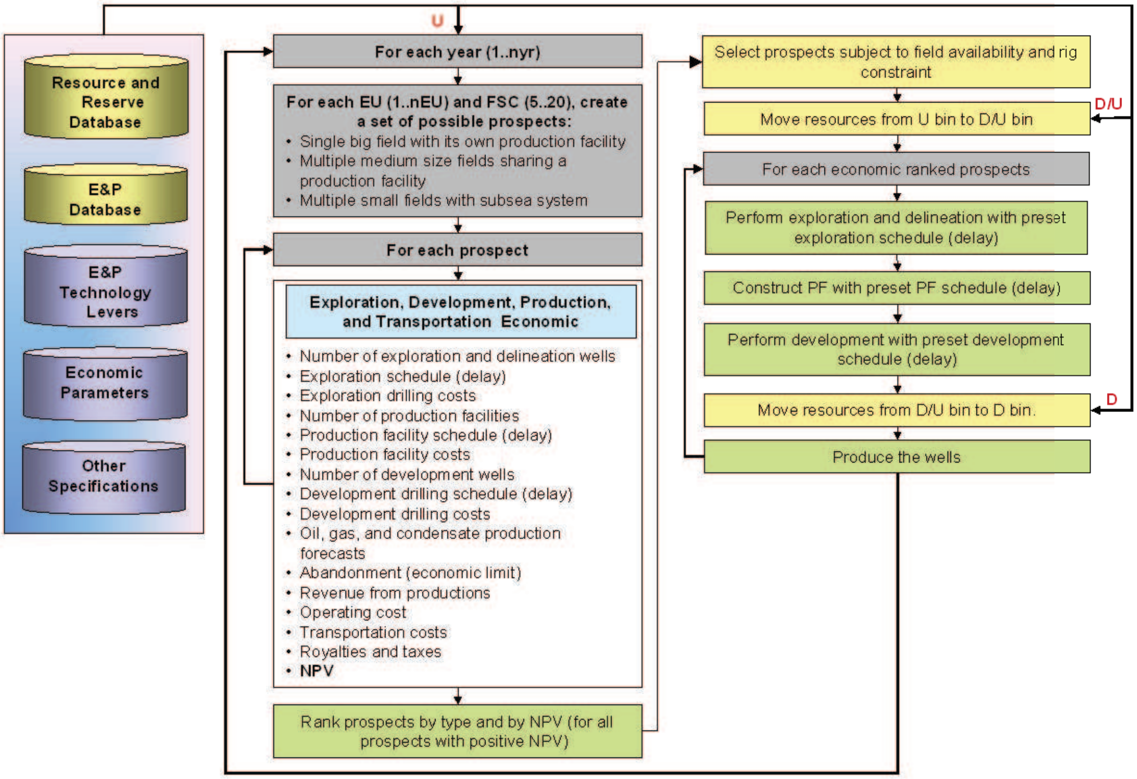
The decision for exploration and development of the discoveries determine from Equation 3-1 is performed at a prospect level that could involve more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3-2.

Figure 3-1. Prospect Exploration, Development, and Production Schedule



Source: ICF Consulting

Figure 3-2. Flowchart for the Undiscovered Field Component of the OOGSS



Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

Calculation of Costs

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. The following base costs are adjusted with the oil price to capture the variation in costs over time as activity level and demand for equipment and other supplies change. The adjustment factor is [1 + (oilprice/baseprice – 1)*0.4], where baseprice = $30/barrel.

Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

Jack-up rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}000{,}000 + (5.0\text{E-}09)*WD*DD^3 \tag{3-4}$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}500{,}000 + 200*(WD+DD) + WD*(400+(2.0\text{E-}05)*DD^2) \tag{3-5}$$

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

$$\text{ExplorationDrillingCosts(\$/well)} = 7{,}000{,}000 + (1.0\text{E-}05)*WD*DD^2 \tag{3-6}$$

Water depth is the primary criterion for selecting a drilling rig. Drilling in shallow waters (up to 1,500 feet) can be done with jack-up rigs. Drilling in deeper water (greater than 1,500 feet) can be done with semi-submersible drilling rigs or drill ships. The number of rigs available for exploration is limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

Production and Development Structure

Six different options for development/production of offshore prospects are currently assumed in OOGSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

Conventional Fixed Platform (FP). A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

$$\text{StructureCost}(\$) = 2{,}000{,}000 + 9{,}000 * \text{SLT} + 1{,}500 * \text{WD} * \text{SLT} + 40 * \text{WD}^2 \tag{3-7}$$

Compliant Towers (CT). The compliant tower is a narrow, flexible tower type of platform that is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the owerand terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells; however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\text{WD} - 1{,}000)) \tag{3-8}$$

Tension Leg Platform (TLP). The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (3{,}000{,}000 + 750 * (\text{WD} - 1{,}000)) \tag{3-9}$$

Floating Production System (FPS). The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (7{,}500{,}000 + 250 * (\text{WD} - 1{,}000)) \tag{3-10}$$

Spar Platform (SPAR). A Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (3{,}000{,}000 + 500 * (\text{WD} - 1{,}000)) \tag{3-11}$$

Subsea Wells System (SS). Subsea systems range from a single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well is included in the development well drilling and completion costs, no cost is assumed for the subsea well system. However, a subsea template is required for all development wells producing to any structure other than a fixed platform.

$$\text{SubseaTemplateCost}(\$ / \text{well}) = 2{,}500{,}000 \tag{3-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3-4.

Table 3-4. Production Facility by Water Depth Level

Water Depth Range (feet)		Production Facility Type					
Minimum	Maximum	FP	CT	TLP	FPS	SPAR	SS
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Source: ICF Consulting

Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

For water depths less than or equal to 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) = 1{,}500{,}000 + (1{,}500 + 0.04 * \text{DD}) * \text{WD} \\ +(0.035 * \text{DD} - 300) * \text{DD}\end{aligned} \qquad (3\text{-}13)$$

For water depths greater tan 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$ / \text{well}) = 4{,}500{,}000 + (150 + 0.004 * \text{DD}) * \text{WD} \\ +(0.035 * \text{DD} - 250) * \text{DD}\end{aligned} \qquad (3\text{-}14)$$

where

WD = water depth in feet
DD = drilling depth in feet.

Completion and Operating

Completion costs per well are a function of water depth range and drilling depth as shown in Table 3-5.

Table 3-5. Well Completion and Equipment Costs per Well

Water Depth (feet)	Development Drilling Depth (feet)		
	< 10,000	10,001 - 20,000	> 20,000
0 - 3,000	800,000	2,100,000	3,300,000
> 3,000	1,900,000	2,700,000	3,300,000

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). These costs include the following items:

- primary oil and gas production costs,
- labor,
- communications and safety equipment,
- supplies and catering services,
- routine process and structural maintenance,
- well service and workovers,
- insurance on facilities, and
- transportation of personnel and supplies.

Annual operating costs are estimated by

$$\text{OperatingCost}(\$ / \text{structure} / \text{year}) = 1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2 \qquad (3\text{-}15)$$

Transportation

It is assumed in the model that existing trunk pipelines will be used and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Structure and Facility Abandonment

The costs to abandon the development structure and production facilities depend on the type of production technology used. The model projects abandonment costs for fixed platforms and compliant towers assuming that the structure is abandoned. It projects costs for tension leg platforms, converted semi-submersibles, and converted tankers assuming that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based on historical data, these costs are estimated as a fraction of the initial structure costs, as follows:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

Exploration, Development, and Production Scheduling

The typical offshore project development consists of the following phases:[3]

- Exploration phase,
    - Exploration drilling program
    - Delineation drilling program
- Development phase,
- Fabrication and installation of the development/production platform,
    - Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
    - Construction of gathering system
- Production operations, and
- Field abandonment.

---

[3] The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one of the four wildcat wells drilled finds the field and the other three are dry holes.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends on the type of system used. The required time for construction and installation of the various development structures used in the model is shown in Table 3-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Development drilling schedule. The number of development wells varies by water depth and field size class as follows.

$$\text{DevelopmentWells} = \frac{5}{\text{FSC}} * \text{FSIZE}^{\beta_{\text{DepthClass}}} \tag{3-16}$$

where

FSC = field size class
FSIZE = resource volume (MMBOE)

β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

Table 3-6. Production Facility Design, Fabrication, and Installation Period (Years)

PLATFORMS	Water Depth (Feet)														
Number of Slots	0	100	400	800	1000	1500	2000	3000	4000	5000	6000	7000	8000	9000	10000
2	1	1	1	1	1	1	1	1	2	2	3	3	4	4	4
8	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
12	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
18	2	2	2	2	2	2	2	2	2	3	3	3	4	4	4
24	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
36	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
48	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
60	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
OTHERS															
SS	1	1	1	1	1	1	2	2	2	3	3	3	4	4	4
FPS								3	3	3	4	4	4	4	5

Source: ICF Consulting

The development drilling schedule is determined based on the assumed drilling capacity (maximum number of wells that could be drilled in a year). This drilling capacity varies by type of production facility and water depth. For a platform type production facility (FP, CT, or TLP), the development drilling capacity is also a function of the number of slots. The assumed drilling capacity by production facility type is shown in Table 3-7.

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

Table 3-7. Development Drilling Capacity by Production Facility Type

Maximum Number of Wells Drilled (wells/platform/year, 1 rig)	
Drilling Depth (feet)	Drilling Capacity (24 slots)
0	24
6000	24
7000	24
8000	20
9000	20
10000	20
11000	20
12000	16
13000	16
14000	12
15000	8
16000	4
17000	2
18000	2
19000	2
20000	2
30000	2

Maximum Number of Wells Drilled (wells/field/year)			
Water Depth (feet)	SS	FPS	FPSO
0	4	■	4
1000	4	■	4
2000	4	■	4
3000	4	4	4
4000	4	4	4
5000	3	3	3
6000	2	2	2
7000	2	2	2
8000	1	1	1
9000	1	1	1
10000	1	1	1

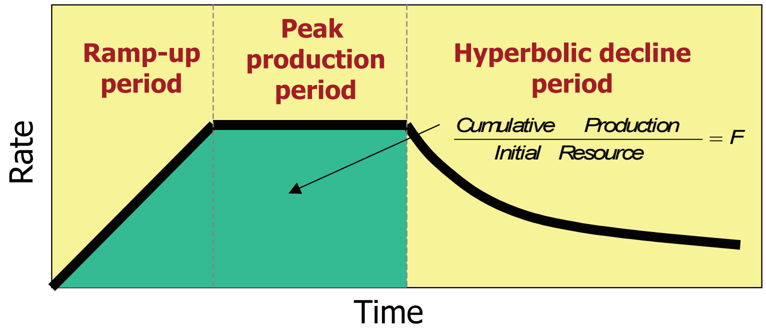
Source: ICF Consulting

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3-3). The initial production rate is the same for all wells in the field and is constant for a period of time. Field production reaches its peak when all the wells have been drilled and start producing. The production will start to decline (at a user specified rate) when the ratio of cumulative production to initial resource equals a user specified fraction.

Gas (plus lease condensate) production is calculated based on gas resource, and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

Figure 3-3. Undiscovered Field Production Profile



Source: ICF Consulting

Field Abandonment

All wells in a field are assumed to be shut-in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource for each field corresponds to the field size class as specified in Table 3-3.

The number of development wells is the same as that of an undiscovered field in the same water depth and of the same field size class (Equation 3-13). The production profile is also the same as that of an undiscovered field (Figure 3-3).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2009 are shown in Table 3-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field include location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

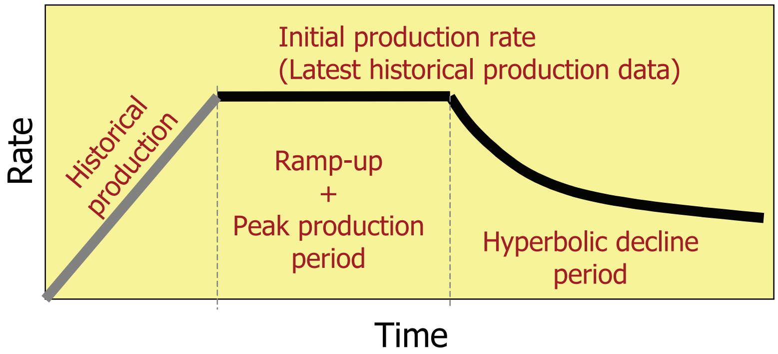
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3-5). The model assumes that production will decline according to a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3-9. Associated-dissolved gas and lease condensate production are determined the same way as in the undiscovered field component.

Table 3-8. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Great White	AC857	8717	2002	14	372	2010
Telemark	AT063	4457	2000	12	89	2010
Ozona	GB515	3000	2008	12	89	2011
West Tonga	GC726	4674	2007	12	89	2011
Gladden	MC800	3116	2008	12	89	2011
Pony	GC468	3497	2006	13	182	2013
Knotty Head	GC512	3557	2005	15	691	2013
Puma	GC823	4129	2003	14	372	2013
Big Foot	WR029	5235	2005	12	89	2013
Cascade	WR206	8143	2002	14	372	2013
Chinook	WR469	8831	2003	14	372	2013
Pyrenees	GB293	2100	2009	12	89	2014
Kaskida	KC292	5860	2006	15	691	2014
Appaloosa	MC503	2805	2008	14	372	2014
Jack	WR759	6963	2004	14	372	2014
Samurai	GC432	3400	2009	12	89	2015
Wide Berth	GC490	3700	2009	12	89	2015
Manny	MC199	2478	2010	13	182	2015
Kodiak	MC771	4986	2008	15	691	2015
St. Malo	WR678	7036	2003	14	372	2015
Mission Deep	GC955	7300	2006	13	182	2016
Tiber	KC102	4132	2009	16	1419	2016
Vito	MC984	4038	2009	13	182	2016
Stones	WR508	9556	2005	12	89	2016
Heidelberg	GB859	5000	2009	13	182	2017
Freedom	MC948	6095	2008	15	691	2017
Shenandoah	WR052	5750	2009	13	182	2017
Buckskin	KC872	6920	2009	13	182	2018
Julia	WR627	7087	2007	12	89	2018
Vicksburg	DC353	7457	2009	14	372	2019
Lucius	KC875	7168	2009	13	182	2019

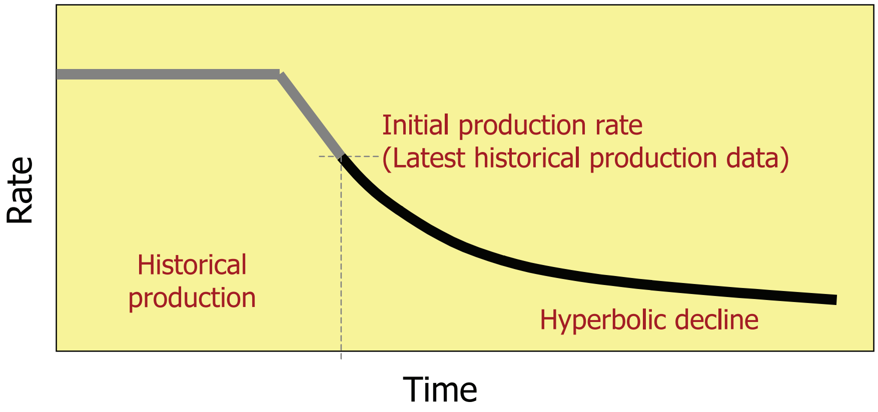
Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Figure 3-4. Production Profile for Producing Fields - Constant Production Case



Source: ICF Consulting

Figure 3-5. Production Profile for Producing Fields - Declining Production Case



Source: ICF Consulting

Table 3-9. Production Profile Data for Oil & Gas Producing Fields

Region	Crude Oil						Natural Gas					
	FSC 2 - 10			FSC 11 – 17			FSC 2 - 10			FSC 11 - 17		
	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate
Shallow GOM	2	2	0.15	3	3	0.10	2	1	0.20	3	2	0.10
Deep GOM	2	2	0.20	2	3	0.15	2	2	0.25	3	2	0.20
Atlantic	2	2	0.20	3	3	0.20	2	1	0.25	3	2	0.20
Pacific	2	2	0.10	3	2	0.10	2	1	0.20	3	2	0.20

FSC = Field Size Class
Source: ICF Consulting

Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in a given projection year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration. For each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as

$$\mathrm{RESOFF}_{r,k,t+1} = \mathrm{RESOFF}_{r,k,t} - \mathrm{PRDOFF}_{r,k,t} + \mathrm{NRDOFF}_{r,k,t} + \mathrm{REVOFF}_{r,k,t} \qquad (3\text{-}17)$$

where

RESOFF = beginning- of-year reserves
PRDOFF = production
NRDOFF = new reserve discoveries
REVOFF = reserve extensions, revisions, and adjustments
r = region (1=Atlantic, 2=Pacific, 3=GOM)
k = fuel type (1=oil; 2=nonassociated gas)
t = year.

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$\mathrm{NRDOFF}_{r,k,t} = \mathrm{NFDISC}_{r,k,t-1} * \left(\frac{1}{\mathrm{RSVGRO}_k} \right) \qquad (3\text{-}18)$$

$$\mathrm{NIRDOFF}_{r,k,t} = \mathrm{NFDISC}_{r,k,t-1} * \left(1 - \frac{1}{\mathrm{RSVGRO}_k} \right) \qquad (3\text{-}19)$$

where

NRDOFF = new reserve discovery
NIRDOFF = new inferred reserve additions
NFDISC = new field discoveries
RSVGRO = reserves growth factor (8.2738 for oil and 5.9612 for gas)
r = region (1=Atlantic, 2=Pacific, 3=GOM)
k = fuel type (1=oil; 2=gas)

t = year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, the reserves needed to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Solving Equation 3-1 for $REVOFF_{r,k,t}$ and writing

gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t+1}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \tag{3-20}$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base. Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The OOGSS has been designed to give due consideration to the effect of advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3-10.

Table 3-10. Offshore Exploration and Production Technology Levers

Technology Lever	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between exploration	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: ICF Consulting

Appendix 3.A. Offshore Data Inventory

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CPRDOFF	COPRD	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CUMDISC	DiscoveredFields	Cumulative number of dicovered offshore fields	NA	Offshore evaluation unit: Field size class
CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	NA	Offshore evaluation unit: Field size class
CURPRROFF	omega	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CURRESOFF	R	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
DECLOFF	--	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
DEVLCOST	DevelopmentDrilling Cost	Development drilling cost	$ per well	Offshore evaluation unit
DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions
DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
DVWELLOFF	--	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
ELASTOFF	--	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions
EXPLCOST	ExplorationDrillingCosts	Exploration well drilling cost	$ per wells	Offshore evaluation unit
EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions
FLOWOFF	--	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
INFRSVOFF	I	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
KAPFRCOFF	EXKAP	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)
KAPSPNDOFF	KAP	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions
NDEVWLS	DevelopmentWells	Number of development wells drilled	NA	Offshore evaluation unit
NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
NFWELLOFF	--	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1
NIRDOFF	NIRDOFF	Offshore new inferred reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions
OPRCOST	OperatingCost	Operating cost	$ per well	Offshore evaluation unit
PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
PRJOFF	N	Offshore project life	Years	Fuel (oil, gas)
RCPRDOFF	M	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore
RESOFF	RESOFF	Offshore reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
REVOFF	REVOFF	Offshore reserve revisions	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
SC	Γ	Search coefficient for discovery model	Fraction	Offshore evaluation unit: Field size class
SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
STTXOFF	STRT	State tax rates	fraction	4 Lower 48 offshore subregions
TECHOFF	TECH	Offshore technology factors applied to costs	fraction	Lower 48 Offshore
TRANSOFF	TRANS	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)
UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRLAG	--	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;
WDCFOFFLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)
WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA

PARAMETERS		
Parameter	Description	Value
nREG	Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC)	4
nPA	Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND)	13
ntEU	Total number of evaluation units (43)	43
nMaxEU	Maximum number of EU in a PA (6)	6
TOTFLD	Total number of evaluation units	3600
nANN	Total number of announce discoveries	127

PARAMETERS		
Parameter	Description	Value
nPRD	Total number of producing fields	1132
nRIGTYP	Rig Type (1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000)	8
nPFTYP	Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS))	7
nPFWDR	Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET)	5
NSLTIdx	Number of platform slot data points	8
NPFWD	Number of production facility water depth data points	15
NPLTDD	Number of platform water depth data points	17
NOPFWD	Number of other production facitlity water depth data points	11
NCSTWD	Number of water depth data points for production facility costs	39
NDRLWD	Number of water depth data points for well costs	15
NWLDEP	Number of well depth data points	30
TRNPPLNCSTNDIAM	Number of pipeline diameter data points	19
MAXNFIELDS	Maximum number of fields for a project/prospect	10
nMAXPRJ	Maximum number of projects to evaluate per year	500
PRJLIFE	Maximum project life in years	10

INPUT DATA			
Variable	Description	Unit	Source
ann_EU	Announced discoveries - Evaluation unit name	-	PGBA
ann_FAC	Announced discoveries - Type of production facility	-	BOEMRE
ann_FN	Announced discoveries - Field name	-	PGBA
ann_FSC	Announced discoveries - Field size class	integer	BOEMRE
ann_OG	Announced discoveries - fuel type	-	BOEMRE
ann_PRDSTYR	Announced discoveries - Start year of production	integer	BOEMRE
ann_WD	Announced discoveries - Water depth	feet	BOEMRE
ann_WL	Announced discoveries - Number of wells	integer	BOEMRE
ann_YRDISC	Announced discoveries - Year of discovery	integer	BOEMRE
beg_rsva	AD gas reserves	bcf	calculated in model
BOEtoMcf	BOE to Mcf conversion	Mcf/BOE	ICF
chgDrlCstOil	Change of Drilling Costs as a Function of Oil Prices	fraction	ICF
chgOpCstOil	Change of Operating Costs as a Function of Oil Prices	fraction	ICF
chgPFCstOil	Change of Production facility Costs as a Function of Oil Prices	fraction	ICF
cndYld	Condensate yield by PA, EU	Bbl/mmcf	BOEMRE
cstCap	Cost of capital	percent	BOEMRE
dDpth	Drilling depth by PA, EU, FSC	feet	BOEMRE
deprSch	Depreciation schedule (8 year schedule)	fraction	BOEMRE
devCmplCst	Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	million 2003 dollars	BOEMRE
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
devDrlDly24	Maximum number of development wells drilled from a 24-slot PF by drilling depth index	Wells/PF/year	ICF
devDrlDlyOth	Maximum number of development wells drilled for other PF by PF type, water depth index	Wells/field/year	ICF

INPUT DATA			
Variable	Description	Unit	Source
devOprCst	Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	2003 $/well/year	BOEMRE
devTangFrc	Development Wells Tangible Fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	BOEMRE
Drillcap	Drilling Capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (Years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean Exploratory Well Costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
ExpTangFrc	Exploration and Delineation Wells Tangible Fraction	fraction	ICF
fedTaxRate	Federal Tax Rate	percent	ICF
fldExpRate	Maximum Field Exploration Rate	percent	ICF
gasprice	Gas wellhead price by region	2003$/mcf	NGTDM
gasSevTaxPrd	Gas production severance tax	2003$/mcf	ICF
gasSevTaxRate	Gas severance tax rate	percent	ICF
GOprop	Gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Gas-to-Oil ratio (Scf/Bbl) by PA, EU	Scf/Bbl	ICF
GORCutOff	GOR cutoff for oil/gas field determination	-	ICF
gRGCGF	Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index	-	BOEMRE
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	PGBA
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	PGBA
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	PGBA
levExpSucRate	Seismic technology (increase exploration success rate)	percent	PGBA
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	PGBA
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	PGBA
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	PGBA
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	PGBA
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	PGBA
nDelWls	Number of delineation wells to justify a production facility by PA, EU, FSC	integer	ICF
nDevWls	Maximum number of development wells by PA, EU, FSC	integer	ICF
nEU	Number of evaluation units in each PA	integer	ICF
nmEU	Names of evaluation units by PA	-	ICF
nmPA	Names of planning areas by PA	-	ICF
nmPF	Name of production facility and subsea-system by PF type index	-	ICF
nmReg	Names of regions by region	-	ICF
ndiroff	Additions to inferred reserves by region and fuel type	oil: MBbls; gas: Bcf	calculated in model
nrdoff	New reserve discoveries by region and fuel type	oil: Mbbls; gas: Bcf	calculated in model
nRigs	Number of rigs by rig type	integer	ICF

INPUT DATA			
Variable	Description	Unit	Source
nRigWlsCap	Number of well drilling capacity (Wells/Rig)	wells/rig	ICF
nRigWlsUtl	Number of wells drilled (Wells/Rig)	wells/rig	ICF
nSlt	Number of slots by # of slots index	integer	ICF
oilPrcCstTbl	Oil price for cost tables	2003$/Bbl	ICF
oilprice	Oil wellhead price by region	2003$/Bbl	PMM
oilSevTaxPrd	Oil production severance tax	2003$/Bbl	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index	fraction	BOEMRE
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by PA	-	ICF
pfBldDly1	Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003 $	BOEMRE
pfCstFrc	Production facility cost fraction matrix by year index, year index	fraction	ICF
pfMaxNFld	Maximum number of fields in a project by project option	integer	ICF
pfMaxNWls	Maximum number of wells sharing a flowline by project option	integer	ICF
pfMinNFld	Minimum number of fields in a project by project option	integer	ICF
pfOptFlg	Production facility option flag by water depth range index, FSC	-	ICF
pfTangFrc	Production Facility Tangible Fraction	fraction	ICF
pfTypFlg	Production facility type flag by water depth range index, PF type index	-	ICF
platform	Flag for platform production facility	-	ICF
prd_DEPTH	Producing fields - Total drilling depth	feet	BOEMRE
prd_EU	Producing fields - Evaluation unit name	-	ICF
prd_FLAG	Producing fields - Production decline flag	-	ICF
prd_FN	Producing fields - Field name	-	BOEMRE
prd_ID	Producing fields - BOEMRE field ID	-	BOEMRE
prd_OG	Producing fields - Fuel type	-	BOEMRE
prd_YRDISC	Producing fields - Year of discovery	year	BOEMRE
prdDGasDecRatei	Initial gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Gas hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDOilDecRatei	Initial oil decline rate by PA, EU,	fraction/year	ICF
prdDOilHyp	Oil hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDYrPeakGas	Years at peak production for gas by PA, EU, FSC, range index	number of years	ICF
prdDYrPeakOil	Years at peak production for oil by PA, EU, FSC, range index	number of years	ICF
prdDYrRampUpGas	Years to ramp up for gas production by PA, EU, FSC range index	number of years	ICF
prdDYrRampUpOil	Years to ramp up for oil production by PA, EU, FSC range index	number of years	ICF
prdGasDecRatei	Initial gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of gas produced before decline by PA, EU	fraction	ICF
prdGasHyp	Gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial gas production (Mcf/Day/Well) by PA, EU	Mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel typ	fraction	PGBA
prdoff	Expected production by fuel type	oil:MBbls; gas: Bcf	calculated in model
prdOilDecRatei	Initial oil decline rate by PA, EU	fraction/year	ICF
prdOilFrc	Fraction of oil produced before decline by PA, EU	fraction	ICF

INPUT DATA			
Variable	Description	Unit	Source
prdOilHyp	Oil hyperbolic decline coefficient by PA, EU	fraction	ICF
prdOilRatei	Initial oil production (Bbl/Day/Well) by PA, EU	Bbl/day/well	ICF
prod	Producing fields - annual production by fuel type	oil:MBbls; gas:Mmcf	BOEMRE
prod_asg	AD gas production	bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:MBbls; gas:Bcf	
rigBldRatMax	Maximum Rig Build Rate by rig type	percent	ICF
rigIncrMin	Minimum Rig Increment by rig type	integer	ICF
RigUtil	Number of wells drilled	wells/rig	ICF
rigUtilTarget	Target Rig Utilization by rig type	percent	ICF
royRateD	Royalty rate for discovered fields by PA, EU, FSC	fraction	BOEMRE
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	BOEMRE
stTaxRate	Federal Tax Rate by PA, EU	percent	ICF
trnFlowLineLen	Flowline length by PA, EU	Miles/prospect	ICF
trnPpDiam	Oil pipeline diameter by PA, EU	inches	ICF
trnPplnCst	Pipeline cost by region, pipe diameter index, water depth index	million 2003 $/mile	BOEMRE
trnTrfGas	Gas pipeline tariff ($/Mcf) by PA, EU	2003 $/Bbl	ICF
trnTrfOil	Oil pipeline tariff ($/Bbl) by PA, EU	2003 $/Bbl	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	BOEMRE
vMean	Geometric mean MMBOE of FSC	MMBOE	BOEMRE
vMin	Minimum MMBOE of FSC	MMBOE	BOEMRE
wDpth	Water depth by PA, EU, FSC	feet	BOEMRE
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF
Sources: BOEMRE = Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly the Minerals Management Service); ICF = ICF Consulting; PGBA = EIA, Office of Petroleum, Gas, and Biofuels Analysis			

4. Alaska Oil and Gas Supply Submodule

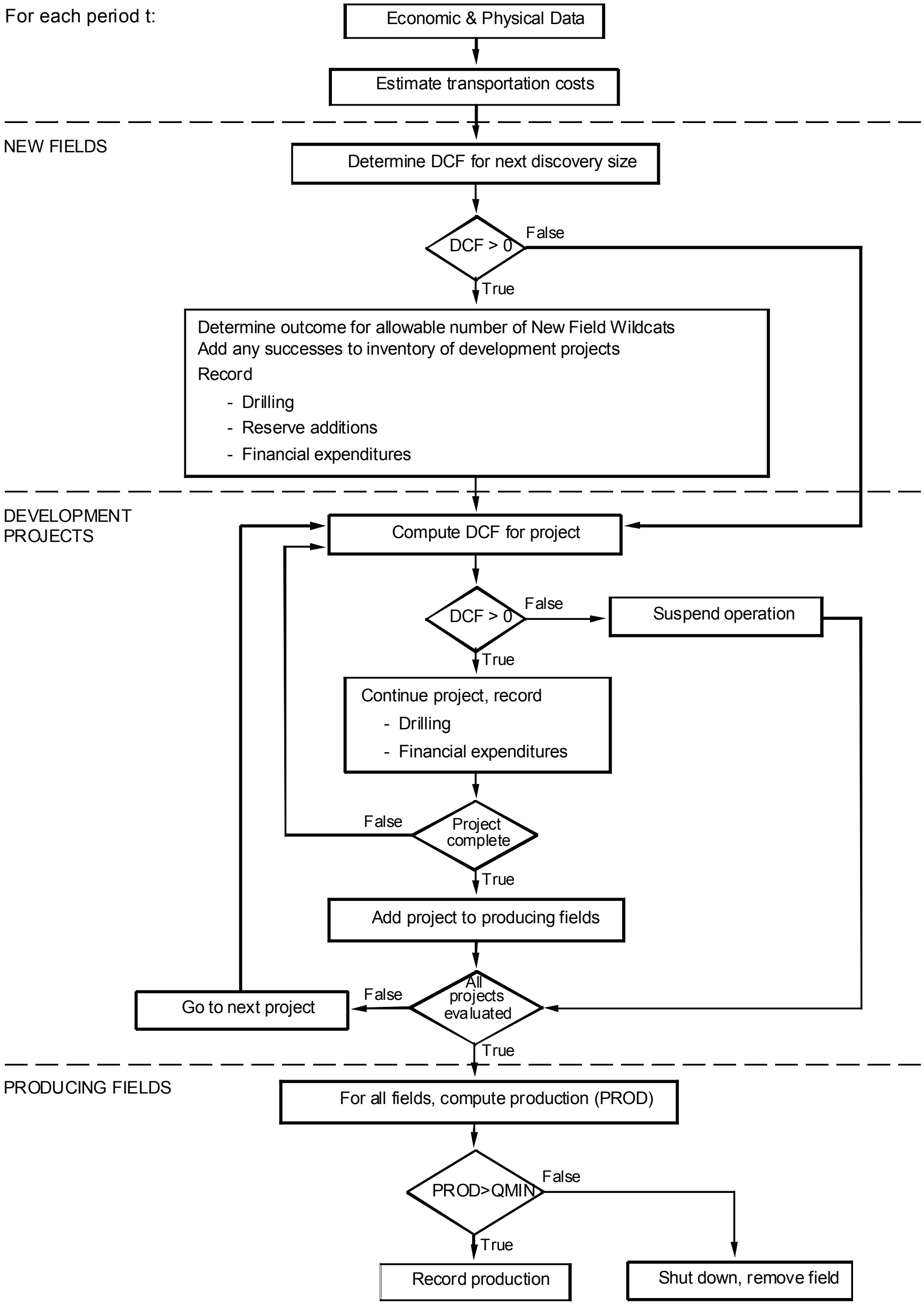
This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil production from the Onshore North Slope, Offshore North Slope, and Other Alaska areas (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Arctic National Wildlife Refuge area in the east. This section provides an overview of the basic modeling approach, including a discussion of the discounted cash flow (DCF) method.

Alaska natural gas production is not projected by the AOGSS, but by Natural Gas Transmission and Distribution Module (NGTDM). The NGTDM projects Alaska gas consumption and whether an Alaska gas pipeline is projected to be built to carry Alaska North Slope gas into Canada and U.S. gas markets. As of January 1, 2009, Alaska was estimated to have 7.7 trillion cubic feet of proved reserves, 24.8 trillion cubic feet of inferred resources at existing fields (also known as field appreciation), and 257.5 trillion cubic feet of undiscovered resources, excluding the Arctic National Wildlife Refuge undiscovered gas resources. Over the long term, Alaska natural gas production is determined by and constrained by local consumption and by the capacity of a gas pipeline that might be built to serve Canada and U.S. lower-48 markets. The proven and inferred gas resources alone (i.e. 32.5 trillion cubic feet), plus known but undeveloped resources, are sufficient to satisfy at least 20 years of Alaska gas consumption and gas pipeline throughput. Moreover, large deposits of natural gas have been discovered (e.g., Point Thomson) but remain undeveloped due to a lack of access to gas consumption markets. Because Alaska natural gas production is best determined by projecting Alaska gas consumption and whether a gas pipeline is put into operation, the AOGSS does not attempt to project new gas field discoveries and their development or the declining production from existing fields.

AOGSS Overview

The AOGSS solely focuses on projecting the exploration and development of undiscovered oil resources, primarily with respect to the oil resources expected to be found onshore and offshore in North Alaska. The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 4-1). Transportation costs are used in conjunction with the crude oil price to Southern California refineries to calculate an estimated wellhead (netback) oil price. A discounted cash flow (DCF) calculation is used to determine the economic viability of Alaskan drilling and production activities. Oil field investment decisions are modeled on the basis of discrete projects. The exploration, discovery, and development of new oil fields depend on the expected exploration success rate and new field profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, along with historical production patterns and announced plans for currently producing fields.

Figure 4-1. Flowchart of the Alaska Oil and Gas Supply Submodule



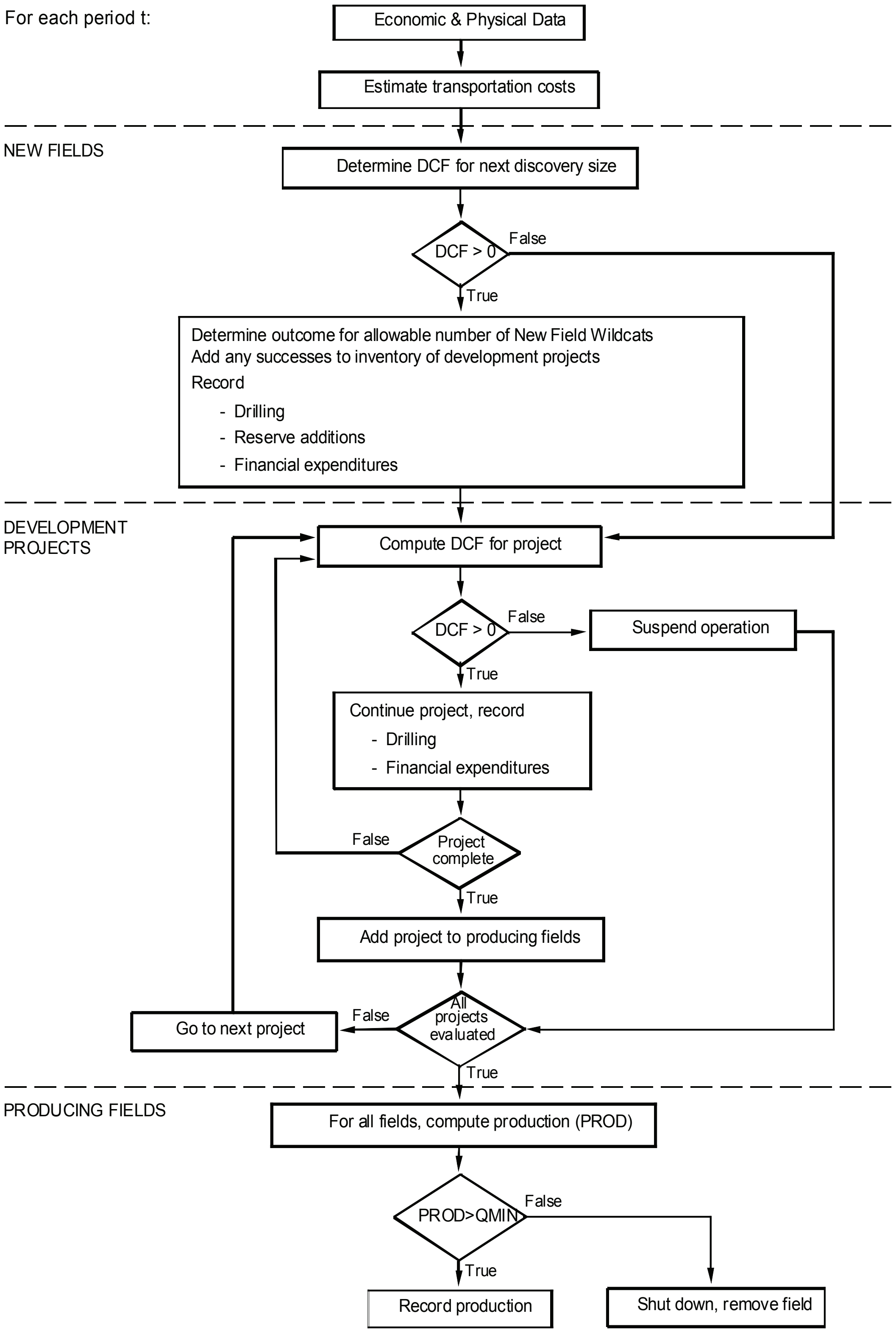
Calculation of Costs

Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as

- Drilling costs,
- Lease equipment costs, and
- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms



relative to what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48 but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and dry holes, and for equipping successful wells through the "Christmas tree," the valves and fittings assembled at the top of a well to control the fluid flow. Elements included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$\mathrm{DRILLCOST}_{i,r,k,t} = \mathrm{DRILLCOST}_{i,r,k,T_b} * (1 - \mathrm{TECH1}) ** (t - T_b) \qquad (4\text{-}1)$$

where

i = well class (exploratory=1, developmental=2)
r = region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k = fuel type (oil=1, gas=2 - but not used)
t = forecast year
DRILLCOST = drilling costs
T_b = base year of the forecast
TECH1 = annual decline in drilling costs due to improved technology.

The above function specifies that drilling costs decline at the annual rate specified by TECH1. Drilling costs are not modeled as a function of the drilling rig activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once drilling rigs are moved up to Alaska and reconfigured for Arctic conditions, they typically remain in Alaska. Company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of the limited number of drilling rigs and equipment available for use. Most Alaska oil rig activity pertains to drilling in-fill wells intended to slow the rate of production decline in the largest Alaska oil fields.

For the *Annual Energy Outlook 2011*, Alaska onshore and offshore drilling and completion costs were updated based on the American Petroleum Institute's (API), *2007 Joint Association Survey on Drilling Costs*, dated December 2008. Based on these API drilling and completion costs and earlier work performed by Advanced Resources International, Inc. in 2002, the following oil well drilling and completion costs were incorporated into the AOGSS database (Table 4.1).

Table 4.1
AOGSS Oil Well Drilling and Completion Costs
By Location and Category
In millions of 2007 dollars

	New Field Wildcat Wells	New Exploration Wells	Developmental Wells
	In millions of 2007 dollars		
Offshore North Slope	206	103	98
Onshore North Slope	150	75	57
South Alaska	73	59	37
	In millions of 1990 dollars		
Offshore North Slope	140	70	67
Onshore North Slope	102	51	39
South Alaska	50	40	25

Table 1 provides both 1990 and 2007 well drilling and completion cost data because the former are used within the context of calculating AOGSS discounted cash flows, while the latter are comparable to the current price environment.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a developed lease. Costs include: producing equipment, the gathering system, processing equipment (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil well is given by:

$$\text{EQUIP}_{r,k,t} = \text{EQUIP}_{r,k,t} * (1 - \text{TECH2})^{r-T_b} \tag{4-2}$$

where

r = region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k = fuel type (oil=1, gas=2 – not used)
t = forecast year
EQUIP = lease equipment costs
T_b = base year of the forecast
TECH2 = annual decline in lease equipment costs due to improved technology.

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$\mathrm{OPCOST}_{r,k,t} = \mathrm{OPCOST}_{r,k,t} * (1 - \mathrm{TECH2})^{r-T_b} \qquad (4\text{-}3)$$

where

r = region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k = fuel type (oil=1, gas=2 – not used)
t = forecast year
OPCOST = operating cost
T_b = base year of the forecast
TECH3 = annual decline in operating costs due to improved technology.

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within each of the three Alaskan regions.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.
- A portion of drilling costs for successful wells is expensed. The specific split between expensing and amortization is based on the tax code.
- Operating costs are expensed.
- All remaining successful field development costs are capitalized.
- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil projects.[1] A positive DCF is necessary to initiate the development of a discovered oil field. With all else being equal, large oil fields are more profitable to develop than small and mid-size fields. In Alaska, where developing new oil fields is quite expensive, particularly in the Arctic, the profitable development of small and mid-size oil fields is generally contingent on the pre-existence of infrastructure that was paid for by the development of a nearby large field. Consequently, AOGSS assumes that the largest oil fields will be developed first, followed by the development of ever smaller oil fields. Whether these oil fields are developed, regardless of their size, is projected on the basis of the profitability index, which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the oil transportation cost to southern California refineries. Transportation costs for Alaskan oil include both pipeline and tanker shipment costs. The oil transportation cost directly affects the expected revenues from the production of a field as follows:[2]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \tag{4-4}$$

where

f = field
t = year
REV = expected revenues
Q = expected production volumes
MP = market price in the lower 48 states
TRANS = transportation cost.

The expected discounted cash flow associated with a potential oil project in field f at time t is given by

$$\begin{aligned} DCF_{f,t} = {} & (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ & - PVOPCOST - PVPRODTAX - PVSIT - PVFIT)_{f,t} \end{aligned} \tag{4-5}$$

where,

PVREV = present value of expected revenues

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[1] See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[2] This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

PVROY = present value of expected royalty payments
PVDRILLCOST = present value of all exploratory and developmental drilling expenditures
PVEQUIP = present value of expected lease equipment costs
TRANSCAP = cost of incremental transportation capacity
PVOPCOST = present value of operating costs
PVPRODTAX = present value of expected production taxes (ad valorem and severance taxes)
PVSIT = present value of expected state corporate income taxes
PVFIT = present value of expected federal corporate income taxes

The expected capital costs for the proposed field f located in region r are:

$$\mathrm{COST}_{f,t} = (\mathrm{PVEXPCOST} + \mathrm{PVDEVCOST} + \mathrm{PVEQUIP} + \mathrm{TRANSCAP})_{f,t} \qquad (4\text{-}6)$$

where

PVEXPCOST = present value exploratory drilling costs
PVDEVCOST = present value developmental drilling costs
PVEQUIP = present value lease equipment costs
TRANSCAP = cost of incremental transportation capacity

The profitability indicator from developing the proposed field is therefore

$$\mathrm{PROF}_{f,t} = \frac{\mathrm{DCF}_{f,t}}{\mathrm{COST}_{f,t}} \qquad (4\text{-}7)$$

The model assumes that field with the highest positive PROF in time t is eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into field reserves requires both a successful new field wildcat well and a positive discounted cash flow of the costs relative to the revenues. The discovery procedure can be determined endogenously, based on exogenously determined data. The procedure requires the following exogenously determined data:

- new field wildcat success rate,
- any restrictions on the timing of drilling,
- the distribution of technically recoverable field sizes within each region.

The endogenous procedure generates:

- the new field wildcat wells drilled in any year,
- the set of individual fields to be discovered, specified with respect to size and location (relative to the 3 Alaska regions, i.e., offshore North Slope, onshore North Slope, and South-Central Alaska),
- an order for the discovery sequence, and
- a schedule for the discovery sequence.

The new field discovery procedure relies on the U.S. Geological Survey (USGS) and Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) respective estimates of onshore and offshore technically recoverable oil resources as translated into the expected field size distribution of undiscovered fields. These onshore and offshore field size distributions are used to determine the field size and order of discovery in the AOGSS exploration and discovery process. Thus, the AOGSS oil field discovery process is consistent with the expected geology with respect to expected aggregate resource base and the relative frequency of field sizes.

AOGSS assumes that the largest fields in a region are found first, followed by successively smaller fields. This assumption is based on the following observations: 1) the largest volume fields typically encompass the greatest areal extent, thereby raising the probability of finding a large field relative to finding a smaller field, 2) seismic technology is sophisticated enough to be able to determine the location of the largest geologic structures that might possibly hold oil, 3) producers have a financial incentive to develop the largest fields first both because of their higher inherent rate of return and because the largest fields can pay for the development of expensive infrastructure that affords the opportunity to develop the smaller fields using that same infrastructure, and 4) historically, North Slope and Cook Inlet field development has generally progressed from largest field to smallest field.

Starting with the AEO2011, onshore and offshore North Slope new field wildcat drilling activity is a function of West Texas Intermediate crude oil prices from 1977 through 2008, expressed in 2008 dollars. The new field wildcat exploration function was statistically estimated based on West Texas Intermdiate crude oil prices from 1977 through 2008 and on exploration well drilling data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) data files for the same period.[3] The North Slope wildcat exploration drilling parameters were estimated using ordinary least squares methodology.

$$\mathrm{NAK\_NFW_t} = (0.13856 * \mathrm{IT\_WOP_t}) + 3.77 \tag{4-8}$$

where

t = year
$\mathrm{NAK\_NFW_t}$ = North Slope Alaska field wildcat exploration wells
$\mathrm{IT\_WOP_t}$ = World oil price in 2008 dollars

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[3] A number of alternative functional formulations were tested (e.g., using Alaska crude oil prices, lagged oil prices, etc.), yet none of the alternative formations resulted in statistically more significant relationships.

The summary statistics for the statistical estimation are as follows:

```
Dependent variable: NSEXPLORE
Current sample:  1 to 32
Number of observations:  32

       Mean of dep. var. = 9.81250      LM het. test = .064580 [.799]
  Std. dev. of dep. var. = 4.41725     Durbin-Watson = 2.04186 [<.594]
Sum of squared residuals = 347.747  Jarque-Bera test = .319848 [.852]
   Variance of residuals = 11.5916   Ramsey's RESET2 = .637229E-04 [.994]
Std. error of regression = 3.40464   F (zero slopes) = 22.1824 [.000]
               R-squared = .425094    Schwarz B.I.C. = 87.0436
      Adjusted R-squared = .405930    Log likelihood = -83.5778

           Estimated    Standard
Variable  Coefficient     Error       t-statistic   P-value
C         3.77029       1.41706       2.66065       [.012]
WTIPRICE  .138559       .029419       4.70982       [.000]
```

Because very few offshore North Slope wells have been drilled since 1977, within AOGSS, the total number of exploration wells drilled on the North Slope are shared between the onshore and offshore regions, with the wells being predominantly drilled onshore in the early years of the projections with progressively more wells drilled offshore, such that after 20 years 50 percent of the exploration wells are drilled onshore and 50 percent are drilled offshore.

Based on the AOGCC data for 1977 through 2008, the drilling of South-Central Alaska new field wildcat exploration wells was statistically unrelated to oil prices. On average, 3 exploration wells per year were drilled in South-Central Alaska over the 1977 through 2008 timeframe, regardless of prevailing oil prices. This result probably stems from the fact that most of the South-Central Alaska drilling activity is focused on natural gas rather than oil, and that natural gas prices are determined by the Regulatory Commission of Alaska rather than being “market driven.” Consequently, AOGSS specifies that 3 exploration wells are drilled each year.

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. State and Federal lease sale schedules could also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in the Arctic National Wildlife Refuge were permitted in 2011, then the earliest possible date at which an ANWR field could begin oil production would be in 2021.[4] Another example is the wide-scale development of the West Sak field that is being delayed until a technology can be developed that will enable the heavy, viscous crude oil of that field to be economically extracted.

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[4] The earliest ANWR field is assumed to go into production 10 years after the first projection year; so the first field comes on line in 2020 for the *Annual Energy Outlook 2010* projections. See also *Analysis of Crude Oil Production in the Arctic National Wildlife Refugee*, EIA, SR/OIAF/2008-03, (May 2008).

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

Each model year, the DCF is calculated for each potential development project. Initially, the model assumes a drilling schedule determined by the user or by some set of specified rules. However, if the DCF for a given project is negative, then development of this project is suspended in the year in which the negative DCF occurs. The DCF for each project is evaluated in subsequent years for a positive value. The model assumes that development would resume when a positive DCF value is calculated.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[5] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to the peak production rate,
- the peak production rate is sustained for 3 to 8 years, and
- after peak production, the production rate declines by 12 to 15 percent per year.

The production algorithm build-up and peak-rate period are based on the expected size of the undiscovered field, with larger fields having longer build-up and peak-rate periods than the smaller fields. The field production decline rates are also determined by the field size.

The pace of development and the ultimate number of wells drilled for a particular field is based on the historical field-level profile adjusted for field size and other characteristics of the field (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for a given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Development fields include fields that have already been discovered but have not begun production. These fields include, for example, a series of expansion fields in both the Prudhoe Bay area, the National Petroleum Reserve - Alaska (NPRA), and for various offshore fields. For these fields, the starting date of production and their production rates were not determined by the discovery process outlined above, but are based on public announcements by the company(s) developing those fields.

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[5] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, EIA (May 2000) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

Producing Fields

Oil production from fields producing as of the initial projection year (e.g., Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. The production decline rates of these fields are periodically recalibrated based on recent field-specific production rates.

Natural gas production from the North Slope for sale to end-use markets depends on the construction of a pipeline to transport natural gas to lower 48 markets.[6] North Slope natural gas production is determined by the carrying capacity of a natural gas pipeline to the lower 48.[7] The Prudhoe Bay Field is the largest known deposit of North Slope gas (24.5 Tcf)[8] and currently all of the gas produced from this field is re-injected to maximize oil production. Total known North Slope gas resources equal 35.4 Tcf.[9] Furthermore, the undiscovered onshore central North Slope and NPRA technically recoverable natural gas resource base are respectively estimated to be 33.3 Tcf[10] and 52.8 Tcf.[11] Collectively, these North Slope natural gas reserves and resources equal 121.5 Tcf, which would satisfy the 1.64 Tcf per year gas requirements of an Alaska gas pipeline for almost 75 years, well after the end of the *Annual Energy Outlook* projections. Consequently, North Slope natural gas resources, both discovered and undiscovered, are more than ample to supply natural gas to an Alaska gas pipeline during the *Annual Energy Outlook* projection period.

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[6] Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction. Details of how this decision is made in NEMS are included in the Natural Gas Transmission and Distribution Module documentation.

[7] The determination of whether an Alaska gas pipeline is economically feasible is calculated within the Natural Gas Transmission and Distribution Model.

[8] *Alaska Oil and Gas Report 2009*, Alaska Department of Natural Resources, Division of Oil and Gas, Table I.I, page 8.

[9] Ibid.

[10] U.S. Geological Survey, *Oil and Gas Assessment of Central North Slope, Alaska, 2005*, Fact Sheet 2005-3043, April 2005, page 2 table – mean estimate total.

[11] U.S. Geological Survey, *2010 Updated Assessment of Undiscovered Oil and Gas Resources of the National Petroleum Reserve in Alaska (NPRA)*, Fact Sheet 2010-3102, October 2010, Table 1 – mean estimate total, page 4.

Appendix 4.A. Alaskan Data Inventory

Variable Name		Description	Unit	Classification	Source
Code	Text				
ANGTSMAX	--	ANGTS maximum flow	BCF/D	Alaska	NPC
ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	NPC
ANGTSRES	--	ANGTS reserves	BCF	Alaska	NPC
ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	NPC
DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	OPNGBA
DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	USGS
EXP_AK	--	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	OPNGBA
FACILAK	--	Alaska facility cost (oil field)	1990$/bls	Field size class	USGS
FSZCOAK	--	Alaska oil field size distributions	MMB	3 Alaska regions	USGS
FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	USGS
HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	AOGCC
KAPFRCAK	EXKAP	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
NAK_NFW	--	Number of new field wildcat wells drilling in Northern AK	wells per year	NA	OPNGBA
NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	OPNGBA
PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	OPNGBA
PROYR	--	Start year for known fields in Alaska	Year	Field	Announced Plans

Variable Name		Description	Unit	Classification	Source
Code	Text				
RCPRDAK	m	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code
RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	USGS
SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	USGS
SRAK	SR	Alaska drilling success rates	fraction	Alaska	OPNGBA
STTXAK	STRT	Alaska state tax rate	fraction	Alaska	USGS
TECHAK	TECH	Alaska technology factors	fraction	Alaska	OPNGBA
TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	OPNGBA
XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code

Source: National Petroleum Council (NPC), EIA Office of Petroleum, Natural Gas, & Biofuels Analysis (OPNGBA), United States Geologic Survey (USGS), Alaska Oil and Gas Conservation Commission (AOGCC)

5. Oil Shale Supply Submodule

Oil shale rock contains a hydrocarbon known as kerogen,[12] which can be processed into a synthetic crude oil (syncrude) by heating the rock. During the 1970s and early 1980s, petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. In one approach, which the majority of the oil companies pursued, the producer mines the oil shale rock in underground mines. A surface facility the retorts the rock to create bitumen, which is then further processed into syncrude. Occidental Petroleum Corp. pursued the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, while the remaining underground rock is "rubblized" using explosives to create large caverns filled with oil shale rock. The rubblized oil shale rock is then set on fire to heat the kerogen and convert it into bitumen, with the bitumen being pumped to the surface for further processing into syncrude. The modified in-situ approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because the leaching of underground bitumen and other petroleum compounds might contaminate underground aquifers.

When oil prices dropped below $15 per barrel in the mid-1990s, demonstrating an abundance of conventional oil supply, oil shale petroleum production became untenable and project sponsors canceled their oil shale research and commercialization programs. Consequently, no commercial-scale oil shale production facilities were ever built or operated. Thus, the technical and economic feasibility of oil shale petroleum production remains untested and unproven.

In 1997, Shell Oil Company started testing a completely in-situ oil shale process, in which the oil shale rock is directly heated underground using electrical resistance heater wells, while petroleum products[13] are produced from separate production wells. The fully in-situ process has significant environmental and cost benefits relative to the other two approaches. The environmental benefits are lower water usage, no waste rock disposal, and the absence of hydrocarbon leaching from surface waste piles. As an example of the potential environmental impact on surface retorting, an industry using 25 gallon per ton oil shale rock to produce 2 million barrels per day would generate about 1.2 billion tons of waste rock per year, which is about 11 percent more than the weight of all the coal mined in the United States in 2010. Other advantages of the in-situ process include: 1) access to deeper oil shale resources, 2) greater oil and gas generated per acre because the process uses multiple oil shale seams within the resource column rather than just a single seam, and 3) direct production of petroleum products rather than

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[12] Kerogen is a solid organic compound, which is also found in coal.

[13] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.

a synthetic crude oil that requires more refinery processing. Lower production costs are expected for the in-situ approach because massive volumes of rock would not be moved, and because the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Personnel safety would be greater and accident liability lower. Moreover, the in-situ process reduces the capital risk, because it involves building self-contained modular production units that can be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been commercially demonstrated, there is already a substantial body of evidence from field tests conducted by Shell Oil Co. that the in-situ process is technologically feasible.[14] The current Shell field research program is expected to conclude around the 2014 through 2017 timeframe with the construction of a small scale demonstration plant expected to begin shortly thereafter. The Oil Shale Supply Submodule (OSSS) assumes that the first commercial size oil shale plant cannot be built prior to 2017.

Given the inherent cost and environmental benefits of the in-situ approach, a number of other companies, such as Chevron and ExxonMobil are testing alternative in-situ oil shale techniques. Although small-scale mining and surface retorting of oil shale is currently being developed, by companies such as Red Leaf Resources, the large scale production of oil shale will most likely use the in-situ process. However, because in-situ oil shale projects have never been built, and because companies developing the in-situ process have not publicly released detailed technical parameters and cost estimates, the cost and operational parameters of such in-situ facilities is unknown. Consequently, the Oil Shale Supply Submodule (OSSS) relies on the project parameters and costs associated with the underground mining and surface retorting approach that were designed during the 1970s and 1980s. In this context, the underground mining and surface retorting facility parameters and costs are meant to be a surrogate for the in-situ oil shale facility that is more likely to be built. Although the in-situ process is expected to result in a lower cost oil shale product, this lower cost is somewhat mitigated by the fact that the underground mining and surface retorting processes developed in the 1970s and 1980s did not envision the strict environmental regulations that prevail today, and therefore embody an environmental compliance cost structure that is lower than what would be incurred today by a large-scale underground mining and surface retorting facility. Also, the high expected cost structure of the underground mining/surface retorting facility constrains the initiation of oil shale project production, which should be viewed as a more conservative approach to simulating the market penetration of in-situ oil projects. On the other hand, OSSS oil shale facility costs are reduced by 1 percent per year to reflect technological progress, especially with respect to the improvement of an in-situ oil shale process. Finally, public opposition to building any type of oil shale facility is likely to be great, regardless of the fact that the in-situ process is expected to be more environmentally benign than the predecessor technologies; the cost of building an in-situ oil shale facility is therefore likely to be considerably greater than would be determined strictly by the engineering parameters of such a facility.[15]

The Oil Shale Supply Submodule (OSSS) only represents economic decision making. In the absence of any existing commercial oil shale projects, it was impossible to determine the

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[14] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

[15] Project delays due to public opposition can significantly increase project costs and reduce project rates of return.

potential environmental constraints and costs of producing oil on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on an in-situ technology, and the infeasibility of the large-scale implementation of an underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, the construction of commercial oil shale projects is constrained by a linear market penetration algorithm that restricts the oil production rate, which, at best, can reach a maximum of 2 million barrels per day by the end of a 40-year period after commercial oil shale facilities are deemed to be technologically feasible (starting in 2017). Whether domestic oil shale production actually reaches 2 million barrels per day at the end of the 40-year period depends on the relative profitability of oil shale facilities. If oil prices are too low to recover the weighted average cost of capital, no new facilities are built. However, if oil prices are sufficiently high to recover the cost of capital, then the rate of market penetration rises in direct proportion to facility profitability. So as oil prices rise and oil shale facility profitability increases, the model assumes that oil shale facilities are built in greater numbers, as dictated by the market penetration algorithm.

The 2 million barrel per day production limit is based on an assessment of what is feasible given both the oil shale resource base and potential environmental constraints.[16] The 40-year minimum market penetration timeframe is based on the observation that "…an oil shale production level of 1 million barrels per day is probably more than 20 years in the future…"[17] with a linear ramp-up to 2 million barrels per day equating to a 40-year minimum.

The actual rate of market penetration in the OSSS largely depends on projected oil prices, with low prices resulting in low rates of market penetration, and with the maximum penetration rate only occurring under high oil prices that result in high facility profitability. The development history of the Canadian oil sands industry is an analogous situation. The first commercial Canadian oil sands facility began operations in 1967; the second project started operation in 1978; and the third project initiated production in 2003.[18] So even though the Canadian oil sands resource base is vast, it took over 30 years before a significant number of new projects were announced. This slow penetration rate, however, was largely caused by both the low world oil prices that persisted from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[19] The rise in oil prices that began in 2003 caused 17 new oil sands projects to be announced by year-end 2007.[20] Oil prices subsequently peaked in July 2008,

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[16] *See* U.S. Department of Energy, "Strategic Significance of America's Oil Shale Resource," March 2004, Volume I, page 23 – which speaks of an "aggressive goal" of 2 million barrels per day by 2020; and Volume II, page 7 – which concludes that the water resources in the Upper Colorado River Basin are "more than enough to support a 2 million barrel/day oil shale industry…"

[17] Source: RAND Corporation, "Oil Shale Development in the United States – Prospects and Policy Issues," MG-414, 2005, Summary page xi.

[18] The owner/operator for each of the 3 initial oil sands projects were respectively Suncor, Syncrude, and Shell Canada.

[19] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[20] Source: Alberta Employment, Immigration, and Industry, "Alberta Oil Sands Industry Update," December 2007, Table 1, pages 17 – 21.

and declined significantly, such that a number of these new projects were put on hold at that time.

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of petroleum per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[21] Consequently, the Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2035.

For each projection year, the oil shale submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's projected crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, the submodule assumes that an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified by the market penetration algorithm. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero; second, by a determination of the number of oil shale projects that can be initiated in that year, based on the maximum total oil shale production level that is permitted by the market penetration algorithm.

In any one year, many oil shale projects can be initiated, raising the projected production rates in multiples of the rate for the standard oil shale facility, which is assumed to be 50,000 barrels per day, per project.

Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology.[22] The facility parameter values and cost estimates in the OSSS are based on information reported for the Paraho Oil Shale Project, and which are inflated to constant 2004 dollars.[23] Oil shale rock mining costs are based on Western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock, [24] because coal

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[21] Source: Culbertson, W. J. and Pitman, J. K. "Oil Shale" in *United States Mineral Resources*, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.

[22] Out of the many demonstration projects in the 1970s only Occidental Petroleum tested a modified in-situ approach which used caved-in mining areas to perform underground retorting of the kerogen.

[23] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[24] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of

mining techniques and technology would be employed to mine oil shale rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1 percent per year, starting in 2005, to reflect the role of technological progress in reducing production costs. This cost reduction assumption results in oil shale production costs being 26 percent lower in 2035 relative to the initial 2004 cost structure.

Although the Paraho cost structure might seem unrealistic, given that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, while there is no detailed public information regarding the expected cost of the in-situ process. Even though the in-situ process might be cheaper per barrel of output than the Paraho process, this should be weighted against the following facts 1) oil and gas drilling costs have increased dramatically since 2005, somewhat narrowing that cost difference, and 2) the Paraho costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that an energy production project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volumes of oil and natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative facility cost assessment, which is warranted for a completely new technology.

Another implicit assumption in the OSSS is that the natural gas produced by the facility is sold to other parties, transported offsite, and priced at prevailing regional wellhead natural gas prices. Similarly, the electricity consumed on site is purchased from the local power grid at prevailing industrial prices. Both the natural gas produced and the electricity consumed are valued in the Net Present Value calculations at their respective regional prices, which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[25] Moreover, this treatment of natural gas and electricity prices automatically takes into consideration any embedded carbon dioxide emission costs associated with a particular NEMS scenario, because a carbon emissions allowance cost is embedded in the regional natural gas and electricity prices and costs.

OSSS Oil Shale Facility Configuration and Costs

The OSSS facility parameters and costs are based on those reported for the Paraho Oil Shale

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Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost represents Arch Coal's average western underground mining cost.

[25] The Colorado/Utah/Wyoming region has relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbituminous coal, and 2) the low cost of existing electricity generation equipment, which is inherently lower than new generation equipment due cost inflation and facility depreciation.

project. Because the Paraho Oil Shale Project costs were reported in 1976 dollars, the OSSS costs were inflated to constant 2004 dollar values. Similarly, the OSSS converts NEMS oil prices, natural gas prices, electricity costs, and carbon dioxide costs into constant 2004 dollars, so that all facility net present value calculations are done in constant 2004 dollars. Based on the Paraho Oil Shale Project configuration, OSSS oil shale facility parameters and costs are listed in Table 5-1, along the OSSS variable names. For the *Annual Energy Outlook 2009* and subsequent *Outlooks*, oil shale facility construction costs were increased by 50 percent to represent the world-wide increase in steel and other metal prices since the OSSS was initially designed. For the *Annual Energy Outlook 2011*, the oil shale facility plant size was reduced from 100,000 barrels per day to 50,000 barrels per day, based on discussions with industry representatives who believe that the smaller configuration was more likely for in-situ projects because this size captures most of the economies of scale, while also reducing project risk.

Table 5-1. OSSS Oil Shale Facility Configuration and Cost Parameters

Facility Parameters	OSSS Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	50,000 barrels per day
Oil shale syncrude per ton of rock	OS_GAL_TON	30 gallons
Plant conversion efficiency	OS_CONV_EFF	90 percent
Average facility capacity factor	OS_CAP_FACTOR	90 percent per year
Facility lifetime	OS_PRJ_LIFE	20 years
Facility construction time	OS_PRJ_CONST	3 year
Surface facility capital costs	OS_PLANT_INVEST	$2.4 billion (2004 dollars)
Surface facility operating costs	OS_PLANT_OPER_CST	$200 million per year (2004 dollars)
Underground mining costs	OS_MINE_CST_TON	$17.50 per ton (2004 dollars)
Royalty rate	OS_ROYALTY_RATE	12.5 percent of syncrude value
Carbon Dioxide Emissions Rate	OS_CO2EMISS	150 metric tons per 50,000 bbl/day of production[26]

The construction lead time for oil shale facilities is assumed to be 3 years, which is less than the 5-year construction time estimates developed for the Paraho Project. The shorter construction period is based on the fact that the drilling of shallow in-situ heating and production wells can be accomplished much more quickly than the erection of a surface retorting facility. Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output and that full capacity will be achieved in the second year of operation.

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in the year 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2035, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

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[26] Based on the average of the Fischer Assays determined for four oil shale rock samples of varying kerogen content. Op. cit. Noyes Data Corporation, Table 3.8, page 20.

OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

Based on the Paraho Oil Shale Project parameters, Table 5-2 provides the level of annual gas production and annual electricity consumption for a 50,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[27]

Table 5-2. OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters and Their Prices and Costs

Facility Parameters	OSSS Variable Name	Parameter Value
Natural gas production	OS_GAS_PROD	16.1 billion cubic feet per year
Wellhead gas sales price	OS_GAS_PRICE	Dollars per Mcf (2004 dollars)
Electricity consumption	OS_ELEC_CONSUMP	0.83 billion kilowatt-hours per year
Electricity consumption price	OS_ELEC_PRICE	Dollars per kilowatt-hour (2004 dollars)

Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation expenses, which is then discounted to a net present value. In those future years in which the net present value exceeds zero, a new oil shale facility can begin construction, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 23 year period, composed of 3 years for construction and 20 years for a plant's operating life. During the first 3 years of the 23-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 3 years. In the fourth year, the plant goes into partial operation, and produces 50 percent of the rated output. In the fifth year, revenues and operating expenses are assumed to ramp up to the full-production values, based on a 90 percent capacity factor that allows for potential production outages. During years 4 through 23, total revenues equal oil production revenues plus natural gas production revenues.[28]

Discounted cash flow oil and natural gas revenues are calculated based on prevailing oil and natural gas prices projected for that future year. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil and natural gas at that time in the future and is not based either on historical price trends or future expected prices. Similarly, industrial electricity consumption costs are also based on the prevailing price of electricity for industrial consumers in that region at that future time.

As noted earlier, during a plant's first year of operation (year 4), both revenues and costs are half the values calculated for year 5 through year 23.

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[27] Op. cit. Noyes Data Corporation, pages 89-97.

[28] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 50,000 barrel per day oil shale syncrude facility.

Oil revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} \text{OIL\_REVENUE}_t = {} & \text{OIT\_WOP}_t * (1.083/0.732) * \text{OS\_PRJ\_SIZE} \\ & * \text{OS\_ CAP\_FACTOR} * 365 \end{aligned} \tag{5-8}$$

where

OIT_WOP$_t$ = World oil price at time t in 1987 dollars
(1.083 / 0.732) = GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_PROJ_PRJ_SIZE = Facility project size in barrels per day
OS_CAP_FACTOR = Facility capacity factor
365 = Days per year.

Natural gas revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} \text{GAS\_REVENUE}_t = {} & \text{OS\_GAS\_PROD} * \text{OGPRCL48}_t * 1.083/0.732) \\ & *\text{OS\_CAP\_FACTOR}, \end{aligned} \tag{5-9}$$

where

OS_GAS_PROD = Annual natural gas production for 50,000 barrel per day facility
OGPRCL48$_t$ = Natural gas price in Rocky Mtn. at time t in 1987 dollars
(1.083 / 0.732) = GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR = Facility capacity factor.

Electricity consumption costs are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} \text{ELECT\_COST}_t = {} & \text{OS\_ELEC\_CONSUMP} * \text{PELIN}_t * (1.083/.732) * 0.003412 \\ & * \text{OS\_ CAP\_FACTOR} \end{aligned} \tag{5-10}$$

where

OS_ELEC_CONSUMP = Annual electricity consumption for 50,000 barrel per day facility
PELIN$_t$ = Electricity price Colorado/Utah/Wyoming at time t
(1.083 / .732) = GNP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR = Facility capacity factor.

The carbon dioxide emission tax rate per metric ton is calculated as follows:

$$\text{OS\_EMETAX}_t = \text{EMETAX}_t(1) * 1000.0 * (12.0 / 44.0) * (1.083 / .732) \tag{5-11}$$

where,

$EMETAX_t(1)$ = Carbon emissions allowance price/tax per kilogram at time t

1,000 = Convert kilograms to metric tones

(12.0 / 44.0) = Atomic weight of carbon divided by atomic weight of carbon dioxide

(1.083 / .732) = GNP chain-type price deflators to convert 1987 dollars into 2004 dollars.

Annual carbon dioxide emission costs per plant are calculated as follows:

$$CO2\_COST_t = OS\_EMETAX_t * OS\_CO2EMISS * 365 * OS\_CAP\_FACTOR \tag{5-12}$$

where

OS_EMETAX_t = Carbon emissions allowance price/tax per metric tonne at time t in 2004 dollars

OS_CO2EMISS = Carbon dioxide emissions in metric tonnes per day

365 = Days per year

OS_CAP_FACTOR = Facility capacity factor

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \tag{5-13}$$

where

$TOT\_REVENUE_t$ = Total project revenues at time t

TOT_COST_t = Total project costs at time t.

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \tag{5-14}$$

Total project costs are calculated as follows:

$$\begin{aligned} TOT\_COST_t = {} & OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST \\ & + ELEC\_COST_t + CO2\_COST_t + INVEST_t \end{aligned} \tag{5-15}$$

where

$\mathrm{OS\_PLANT\_OPER\_CST}$ = Annual plant operating costs per year
$\mathrm{ROYALTY}_t$ = Annual royalty costs at time t
$\mathrm{PRJ\_MINE\_COST}$ = Annual plant mining costs
$\mathrm{ELEC\_COST}_t$ = Annual electricity costs at time t
$\mathrm{CO2\_COST}_t$ = Annual carbon dioxide emissions costs at time t
INVEST_t = Annual surface facility investment costs.

While the plant is under construction (years 1 through 3) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (years 4 through 23), the capital costs (INVEST) are zero, while the other five operating costs take on positive values. The annual investment cost for the three years of construction is calculated as follows, under the assumption that the construction costs are evenly spread over the 3-year construction period:

$$\mathrm{INVEST} = \mathrm{OS\_PLANT\_INVEST} / \mathrm{OS\_PRJ\_CONST} \tag{5-16}$$

where the variables are defined as in Table 5-1. Because the plant output is composed of both oil and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$\mathrm{ROYALTY}_t = \mathrm{OS\_ROYALTY\_RATE} * \mathrm{TOT\_REVENUE}_t \tag{5-17}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$\begin{aligned}\mathrm{PRJ\_MINE\_COST} = \mathrm{OS\_MINE\_CST\_TON} * \frac{42}{\mathrm{OS\_GALLON\_TON} * \mathrm{OS\_CONV\_EFF}} \\ * \mathrm{OS\_PROJ\_SIZE} * \mathrm{OS\_CAP\_FACTOR} * 365\end{aligned} \tag{5-18}$$

where

42 = gallons per barrel
365 = days per year.

After the plant goes into operation and after a pre-tax cash flow is calculated, then a post-tax cash flow has to be calculated based on income taxes and depreciation tax credits. When the prevailing world oil price is sufficiently high and the pre-tax cash flow is positive, then the following post-tax cash flow is calculated as

$$\begin{aligned}\mathrm{CASH\_FLOW}_t = (\mathrm{PRETAX\_CASH\_FLOW}_t * (1 - \mathrm{OS\_CORP\_TAX\_RATE})) + \\ (\mathrm{OS\_CORP\_TAX\_RATE} * \mathrm{OS\_PLANT\_INVEST} / \mathrm{OS\_PRJ\_LIFE})\end{aligned} \tag{5-19}$$

The above depreciation tax credit calculation assumes straight-line depreciation over the operating life of the investment (OS_PRJ_LIFE).

Discount Rate Financial Parameters

The discounted cash flow algorithm uses the following financial parameters to determine the discount rate used in calculating the net present value of the discounted cash flow.

Table 5-3. Discount Rate Financial Parameters

Financial Parameters	OSSS Variable Name	Parameter Value
Corporate income tax rate	OS_CORP_TAX_RATE	38 percent
Equity share of total facility capital	OS_EQUITY_SHARE	60 percent
Facility equity beta	OS_EQUITY_VOL	1.8
Expected market risk premium	OS_EQUITY_PREMIUM	6.5 percent
Facility debt risk premium	OS_DEBT_PREMIUM	0.5 percent

The corporate equity beta (OS_EQUITY_VOL) is the project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. The median beta for oil and gas field exploration service firms is about 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.8.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.5 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in the Ba-rating range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The calculation of the discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$\begin{aligned}\mathrm{OS\_DISCOUNT\_RATE}_t = & (((1-\mathrm{OS\_EQUITY\_SHARE})*(\mathrm{MC\_RMCORPBAA}_t/100+ \\ & \mathrm{OS\_DEBT\_PREMIUM}))*(1-\mathrm{OS\_CORP\_TAX\_RATE})+ \\ & (\mathrm{OS\_EQUITY\_SHARE}*((\mathrm{OS\_EQUITY\_PREMIUM}* \\ & \mathrm{OS\_EQUITY\_VOL})+\mathrm{MC\_RMGFCM\_10NS}_t/100))\end{aligned} \tag{5-20}$$

where

OS_EQUITY_SHARE = Equity share of total facility capital
$\mathrm{MC\_RMCORPBAA}_t/100$ = BAA corporate bond rate
OS_DEBT_PREMIUM = Facility debt risk premium
OS_CORP_TAX_RATE = Corporate income tax rate
OS_EQUITY_PREMIUM = Expected market risk premium
OS_EQUITY_VOL = Facility equity volatility beta
$\mathrm{MC\_RMGFCM\_10NS}_t/100$ = 10-year Treasury note rate.

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$\mathrm{OS\_DISCOUNT\_RATE}_t = ((1.0+\mathrm{OS\_DISCOUNT\_RATE}_t)/(1.0+\mathrm{INFL}_t))-1.0 \tag{5-21}$$

where

INFL_t = Inflation rate at time t.

Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

$$\mathrm{NET\_CASH\_FLOW}_{t-1} = \sum_{t=1}^{\mathrm{OS\_PRJ\_LIFE}+\mathrm{OS\_PRJ\_CONST}} \left[\mathrm{CASH\_FLOW}_t * \left[\frac{1}{1+\mathrm{OS\_DISCOUNT\_RATE}_t} \right]^t \right] \tag{5-22}$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil Shale Facility Market Penetration Algorithm

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are three primary constraints to oil shale facility construction. First, the construction of an oil shale facility cannot be undertaken until the in-situ technology has been sufficiently developed and tested to be deemed ready for its application to commercial size projects (i.e., 50,000 barrels per day). Second, oil shale facility construction is constrained by the maximum oil shale production limit. Third, oil shale production volumes cannot reach the maximum oil shale production limit any earlier than 40 years after the in-situ technology has been deemed to be feasible and available for commercial size facilities. Table 5-4 summarizes the primary market penetration parameters in the OSSS.

Table 5-4. Market Penetration Parameters

Market Penetration Parameters	OSSS Variable Name	Parameter Value
Earliest Facility Construction Start Date	OS_START_YR	2017
Maximum Oil Shale Production	OS_MAX_PROD	2 million barrels per year
Minimum Years to Reach Full Market Penetration	OS_PENETRATE_YR	40

Shell's in-situ oil shale RD&D program is considered to be the most advanced, having begun in 1997. Shell is most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility sometime during the 2014 through 2017 timeframe. Consequently, the earliest likely initiation of a full-scale commercial plant would be 2017.[29]

As discussed earlier, a 2 million barrel per day oil shale production level at the end of 40-year market penetration period is considered to be reasonable and feasible based on the size of the resource base and the volume and availability of water needed to develop those resources. The actual rate of market penetration in the OSSS, however, is ultimately determined by the projected profitability of oil shale projects. At a minimum, oil and natural gas prices must be sufficiently high to produce a facility revenue stream (i.e., discounted cash flow) that covers all capital and operating costs, including the weighted average cost of capital. When the discounted cash flow exceeds zero (0), then the market penetration algorithm allows oil shale facility construction to commence.

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[29] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up," and based on public information and private conversations subsequent to the development of that memorandum.

When project discounted cash flow is greater than zero, the relative project profitability is calculated as follows:

$$\text{OS\_PROFIT}_t = \text{DCF}_t \ / \ \text{OS\_PLANT\_INVEST} \tag{5-23}$$

where

DCF_t = Project discounted cash flow at time t
OS_PLANT_INVEST = Project capital investment

OS_PROFIT is an index of an oil project's expected profitability. The expectation is that, as OS_PROFIT increases, the relative financial attractiveness of producing oil shale also increases.

The level of oil shale facility construction that is permitted in any year depends on the maximum oil shale production that is permitted by the following market penetration algorithm:

$$\begin{aligned}\text{MAX\_PROD}_t &= \text{OS\_MAX\_PROD} * (\text{OS\_PROFIT}_t \ / \ (1 + \text{OS\_PROFIT}_t)) \\ &\quad * ((\text{T} - (\text{OS\_START\_YR} - 1989)) \ / \ \text{OS\_PENETRATE\_YR}\ )\end{aligned} \tag{5-24}$$

where,

OS_MAX_PROD = Maximum oil shale production limit
OS_PROFIT_t = Relative oil shale project profitability at time t
T = Time t
OS_START_YR = First year that an oil shale facility can be built
OS_PENTRATE_YR = Minimum number of years during which the maximum oil shale production can be achieved.

The OS_PROFIT portion of the market penetration algorithm (5-24) rapidly increases market penetration as the DCF numerator of OS_PROFIT increases. However, as OS_PROFIT continues to increase, the rate of increase in market penetration slows as (OS_PROFIT / (1 + OS_PROFIT) asymptotically approaches one (1.0). As this term approaches 1.0, the algorithm's ability to build more oil shale plants is ultimately constrained by OS_MAX_PROD term, regardless of how financially attractive the construction of new oil shale facilities might be. This formulation also prevents MAX_PROD from exceeding OS_MAX_PROD.

The second portion of the market penetration algorithm specifies that market penetration increases linearly over the number of years specified by OS_PENETRATE_YR. As noted earlier OS_PENETRATE_YR specifies the minimum number of years over which the oil shale industry can achieve maximum penetration. The maximum number of years required to achieve full penetration is dictated by the speed at which the OS_PROFIT portion of the equation approaches one (1.0). If OS_PROFIT remains low, then it is possible that MAX_PROD never comes close to reaching the OS_MAX_PROD value.

The number of new oil shale facilities that start construction in any particular year is specified by the following equation:

$$OS\_PLANTS\_NEW_t = INT((MAX\_PROD_t - (OS\_PLANTS_t * OS\_PRJ\_SIZE * OS\_CAP\_FACTOR)) / (OS\_PRJ\_SIZE * OS\_CAP\_FACTOR)) \tag{5-25}$$

where

MAX_PROD_t = Maximum oil shale production at time t
OS_PLANT_t = Number of existing oil shale plants at time t
OS_PRJ_SIZE = Standard oil shale plant size in barrels per day
OS_CAP_FACTOR = Annual capacity factor of an oil shale plant in percent per year.

The first portion of the above formula specifies the incremental production capacity that can be built in any year, based on the number of plants already in existence. The latter portion of the equation determines the integer number of new plants that can be initiated in that year, based on the expected annual production rate of an oil shale plant.

Because oil shale production is highly uncertain, not only from a technological and economic perspective, but also from an environmental perspective, an upper limit to oil shale production is assumed within the OSSS. The upper limit on oil shale production is 2 million barrels per day, which is equivalent to 44 facilities of 50,000 barrels per day operating at a 90 percent capacity factor. So the algorithm allows enough plants to be built to fully reach the oil shale production limit, based on the expected plant capacity factor. As noted earlier, the oil shale market penetration algorithm is also limited by the earliest commercial plant construction date, which is assumed to be no earlier than 2017.

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970's and early 1980's, the complete absence of any current commercial-scale oil shale production makes its future economic development highly uncertain. If the technological, environmental, and economic hurdles are as high or higher than those experienced during the 1970's, then the prospects for oil shale development would remain weak throughout the projections. However, technological progress can alter the economic and environmental landscape in unanticipated ways. For example, if an in-situ oil shale process were to be demonstrated to be both technically feasible and commercially profitable, then the prospects for an oil shale industry would improve significantly, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

Appendix A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the effects of multi-year capital investments (e.g., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation A-1).

$$\begin{aligned} DCF_T = (&PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP \\ &- PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \end{aligned} \tag{A-1}$$

where

T = year of evaluation
PVTREV = present value of expected total revenues
PVROY = present value of expected royalty payments
PVPRODTAX = present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST = present value of expected exploratory and developmental drilling expenditures
PVEQUIP = present value of expected lease equipment costs
PVKAP = present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST = present value of expected operating costs
PVABANDON = present value of expected abandonment costs
PVSIT = present value of expected state corporate income taxes
PVFIT = present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation A.1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1]

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[1] The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$\mathrm{WACC} = \frac{\mathrm{D}}{\mathrm{D+E}} * \mathrm{R_D} * (1-\mathrm{t}) + \frac{\mathrm{E}}{\mathrm{D+E}} * \mathrm{R_E} \tag{A-2}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, R_D = cost of debt, and R_E = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by

$$\mathrm{disc} = \frac{(1+\mathrm{WACC})}{(1+\pi_e)} - 1 \tag{A-3}$$

where π_e = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the forecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$\mathrm{PVREV}_{\mathrm{T,k}} = \sum_{\mathrm{t=T}}^{\mathrm{T+n}} \left[\mathrm{Q}_{\mathrm{t,k}} * \lambda * \mathrm{P}_{\mathrm{t,k}} * \left[\frac{1}{1+\mathrm{disc}} \right]^{\mathrm{t-T}} \right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ \text{COPRD if secondary fuel} \end{cases} \tag{A-4}$$

where,

k = fuel type (oil or natural gas)
T = time period
n = number of years in the evaluation period
disc = discount rate
Q = expected production volumes
P = expected net wellhead price
COPRD = co-product factor.[3]

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as follows: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

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[2] Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

[3] The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

The present value of the total expected revenue generated from the representative project is

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{A-5}$$

where

$PVREV_{T,1}$ = present value of expected revenues generated from the primary fuel
$PVREV_{T,2}$ = present value of expected revenues generated from the secondary fuel.

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{A-6}$$

where

ROYRT = royalty rate, expressed as a fraction of gross revenues.

Present Value of Expected Production Taxes

Production taxes consist of ad valorem and severance taxes. The present value of expected production tax is given by

$$\begin{aligned} PVPRODTAX_T = {} & PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2} \\ & *(1 - ROYRT_2) * PRODTAX_2 \end{aligned} \tag{A-7}$$

where

PRODTAX = production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs), and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period).

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor,

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[4] The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. The present value of expected drilling costs is given by

$$\begin{aligned} \mathrm{PVDRILLCOST}_T = \sum_{t=T}^{T+n} \Bigg[\Big[& \mathrm{COSTEXP}_T * \mathrm{SR}_1 * \mathrm{NUMEXP}_t + \mathrm{COSTDEV}_T * \mathrm{SR}_2 * \mathrm{NUMDEV}_t \\ & + \mathrm{COSTDRY}_{T,1} * (1 - \mathrm{SR}_1) * \mathrm{NUMEXP}_t \qquad \text{(A-8)} \\ & + \mathrm{COSTDRY}_{T,2} * (1 - \mathrm{SR}_2) * \mathrm{NUMDEV}_t \Big] * \left(\frac{1}{1 + \mathrm{disc}} \right)^{t-T} \Bigg] \end{aligned}$$

where

COSTEXP = drilling cost for a successful exploratory well
SR = success rate (1=exploratory, 2=developmental)
COSTDEV = drilling cost for a successful developmental well
COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP = number of exploratory wells drilled in a given period
NUMDEV = number of developmental wells drilled in a given period.

The number and schedule of wells drilled for an oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells.

The present value of expected lease equipment cost is

$$\mathrm{PVEQUIP}_T = \sum_{t=T}^{T+n} \left[\mathrm{EQUIP}_t * (\mathrm{SR}_1 * \mathrm{NUMEXP}_t + \mathrm{SR}_2 * \mathrm{NUMDEV}_t) * \left[\frac{1}{1 + \mathrm{disc}} \right]^{t-T} \right] \qquad \text{(A-9)}$$

where

EQUIP = lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as

$$\mathrm{PVKAP}_T = \sum_{t=T}^{T+n} \left[\mathrm{KAP}_t * \left[\frac{1}{1 + \mathrm{disc}} \right]^{t-T} \right] \qquad \text{(A-10)}$$

where

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$\mathrm{PVOPCOST_T} = \sum_{t=T}^{T+n}\left[\mathrm{OPCOST}_t * \sum_{k=1}^{t}\left[\mathrm{SR}_1 * \mathrm{NUMEXP}_k + \mathrm{SR}_2 * \mathrm{NUMDEV}_k\right] * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T}\right] \quad \text{(A-11)}$$

where

OPCOST = operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$\mathrm{PVABANDON_T} = \sum_{t=T}^{T+n}\left[\mathrm{COSTABN}_t * \left[\frac{1}{1+\mathrm{disc}}\right]^{t-T}\right] \quad \text{(A-12)}$$

where

COSTABN = abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs, and other capital costs incurred in each individual year of the evaluation period are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable,[5] depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include

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[5] The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

Key changes in the tax provisions under the tax legislation of 1988 include the following:

- Windfall Profits Tax on oil was repealed,
- Investment Tax Credits were eliminated, and
- Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$\begin{aligned}\mathrm{PVTAXBASE}_{\mathrm{T}} = \sum_{t=T}^{T+n} \Bigg[\Big(&\mathrm{TREV}_{\mathrm{t}} - \mathrm{ROY}_{\mathrm{t}} - \mathrm{PRODTAX}_{\mathrm{t}} - \mathrm{OPCOST}_{\mathrm{t}} - \mathrm{ABANDON}_{\mathrm{t}} - \mathrm{XIDC}_{\mathrm{t}} \\ &- \mathrm{AIDC}_{\mathrm{t}} - \mathrm{DEPREC}_{\mathrm{t}} - \mathrm{DHC}_{\mathrm{t}}\Big) * \left(\frac{1}{1+\mathrm{disc}}\right)^{\mathrm{t-T}} \Bigg]\end{aligned} \qquad \text{(A-13)}$$

where

T = year of evaluation
t = time period
n = number of years in the evaluation period
TREV = expected revenues
ROY = expected royalty payments
PRODTAX = expected production tax payments
OPCOST = expected operating costs
ABANDON = expected abandonment costs
XIDC = expected expensed intangible drilling costs
AIDC = expected amortized intangible drilling costs[6]
DEPREC = expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC = expected dry hole costs
disc = expected discount rate.

$\mathrm{TREV}_{\mathrm{t}}$, $\mathrm{ROY}_{\mathrm{t}}$, $\mathrm{PRODTAX}_{\mathrm{t}}$, $\mathrm{OPCOST}_{\mathrm{t}}$, and $\mathrm{ABANDON}_{\mathrm{t}}$ are the undiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for the purpose of determining corporate income tax liability at the State and Federal level.

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[6] This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table A-1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included.

Table A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s
	5-year SLM[d] 20 percent of IDC=s		
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

[a] Geological and geophysical.
[b] Applicable to marginal project evaluation; first 1,000 barrels per day depletable under percentage depletion.
[c] Modified Accelerated Cost Recovery System; the period of recovery for depreciable costs will vary depending on the type of depreciable asset.
[d] Straight Line Method.

Expected expensed IDC's are defined as follows:

$$\begin{aligned} \mathrm{XIDC_t} = {} & \mathrm{COSTEXP_T} * (1 - \mathrm{EXKAP}) * (1 - \mathrm{XDCKAP}) * \mathrm{SR_1} * \mathrm{NUMEXP_t} \\ & + \mathrm{COSTDEV_T} * (1 - \mathrm{DVKAP}) * (1 - \mathrm{XDCKAP}) * \mathrm{SR_2} * \mathrm{NUMDEV_t} \end{aligned} \quad \text{(A-14)}$$

where

COSTEXP = drilling cost for a successful exploratory well
EXKAP = fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP = fraction of intangible drilling costs that must be depreciated[7]
SR = success rate (1=exploratory, 2=developmental)
NUMEXP = number of exploratory wells
COSTDEV = drilling cost for a successful developmental well
DVKAP = fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV = number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. The model assumes that these costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year; this method of estimating the costs is referred to as the 5-year Straight Line Method (SLM) with half-year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, the recovered costs are estimated using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by

$$\begin{aligned}\mathrm{AIDC}_t = \sum_{j=\beta}^{t} \Big[& \big(\mathrm{COSTEXP}_T * (1-\mathrm{EXKAP}) * \mathrm{XDCKAP} * \mathrm{SR}_1 * \mathrm{NUMEXP}_j \\ & + \mathrm{COSTDEV}_T * (1-\mathrm{DVKAP}) * \mathrm{XDCKAP} * \mathrm{SR}_2 * \mathrm{NUMDEV}_j\big) \\ & * \mathrm{DEPIDC}_t * \left(\frac{1}{1+\mathrm{infl}}\right)^{t-j} * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-j} \Big],\end{aligned} \qquad \text{(A-15)}$$

$$\beta = \begin{cases} T & \text{for } t \le T+m-1 \\ t-m+1 & \text{for } t > T+m-1 \end{cases}$$

where,

j = year of recovery
β = index for write-off schedule
DEPIDC = for t # n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period
infl = expected inflation rate[8]
disc = expected discount rate
m = number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

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[7] The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

[8] The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

$$\mathrm{DHC}_t = \mathrm{COSTDRY}_{T,1} * (1 - \mathrm{SR}_1) * \mathrm{NUMEXP}_t + \mathrm{COSTDRY}_{T,2} * (1 - \mathrm{SR}_2) * \mathrm{NUMDEV}_t \qquad \text{(A-16)}$$

where

COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of XIDC_t, OPCOST_t, $\mathrm{ABANDON}_t$, and DHC_t.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table A-2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

Table A-2. MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$
\begin{aligned}
\mathrm{DEPREC}_t = \sum_{j=\beta}^{t} \Big[\big[& (\mathrm{COSTEXP}_T * \mathrm{EXKAP} + \mathrm{EQUIP}_T) * \mathrm{SR}_1 * \mathrm{NUMEXP}_j \\
& + (\mathrm{COSTDEV}_T * \mathrm{DVKAP} + \mathrm{EQUIP}_T) * \mathrm{SR}_2 * \mathrm{NUMDEV}_j + \mathrm{KAP}_j \big] \\
& * \mathrm{DEP}_{t-j+1} * \left(\frac{1}{1+\mathrm{infl}} \right)^{t-j} * \left(\frac{1}{1+\mathrm{disc}} \right)^{t-j} \Big], \qquad \text{(A-17)} \\
\beta = & \begin{cases} \mathrm{T} \ \text{ for } t \le \mathrm{T} + \mathrm{m} - 1 \\ t - \mathrm{m} + 1 \ \text{ for } \ t > \mathrm{T} + \mathrm{m} - 1 \end{cases}
\end{aligned}
$$

where

j = year of recovery
β = index for write-off schedule
m = number of years in standard recovery period
COSTEXP = drilling cost for a successful exploratory well
EXKAP = fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP = lease equipment costs per well
SR = success rate (1=exploratory, 2=developmental)
NUMEXP = number of exploratory wells
COSTDEV = drilling cost for a successful developmental well
DVKAP = fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV = number of developmental wells drilled in a given period
KAP = major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP = for t # n+T-m, MACRS with half year convention; otherwise, 1/(n+T-t) in each period
infl = expected inflation rate[9]
disc = expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$\mathrm{PVSIT}_T = \mathrm{PVTAXBASE}_T * \mathrm{STRT} \qquad \text{(A-18)}$$

where

PVTAXBASE = present value of expected taxable income (Equation A.14)
STRT = state income tax rate.

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[9] Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

The present value of expected federal corporate income tax is calculated using the following equation:

$$\mathrm{PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT} \qquad \text{(A-19)}$$

where

FDRT = federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as assumed costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

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Appendix C. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Division in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the *Annual Energy Outlook* (DOE/EIA-0383) of the U.S. Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   2010

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   Office: Integrating Analysis and Forecasting
   Division: Oil and Gas Analysis
   Model Contact: Dana Van Wagener
   Telephone: (202) 586-4725

9. Documentation Reference
   U.S. Department of Energy. 2009. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, U.S. Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2010

11. Energy Systems Described
    The OGSM projects oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling activities are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves, and development determines the rate of production from the stock of known reserves.

12. Coverage
    Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
    Time Units/Frequency: Annually 1990 through 2035
    Product(s): Crude oil and natural gas
    Economic Sector(s): Oil and gas field production activities

13. Model Features
    Model Structure: Modular, containing four major components
    - Onshore Lower 48 Oil and Gas Supply Submodule
    - Offshore Oil and Gas Supply Submodule
    - Alaska Oil and Gas Supply Submodule
    - Oil Shale Supply Submodule

    Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are projected using the estimated discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables.
    Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data
    - Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
    - Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
    - Alaska Operating cost - U.S. Geological Survey
    - Basin Differential Prices - Natural Gas Week, Washington, DC
    - State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
    - Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2008)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
    - Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
    - Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
    - Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook*.

- Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report,* Canada, April 2004.
- Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook.*
- Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - Onshore Lease Equipment Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Onshore Operating Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Emissions Factors – U.S. Energy Information Administration
    - Oil and Gas Well Initial Flow Rates – U.S. Energy Information Administration, Office of Oil and Gas
    - Wells Drilled – U.S. Energy Information Administration, Office of Oil and Gas
    - Expected Recovery of Oil and Gas Per Well – U.S. Energy Information Administration, Office of Oil and Gas
    - Oil and Gas Reserves – U.S. Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2009), DOE/EIA-0216(77-09)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT/Windows XP
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: Unknown
    - Estimated Run Time: 287 seconds

17. Reviews conducted
    - Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts

    Not applicable

19. Bibliography

    See Appendix B of this document.

Appendix D. Output Inventory

Variable Name	Description	Unit	Classification	Passed To Module
OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGCCAPPRD	Coalbed Methane production from CCAP		17 OGSM/NGTDM regions	NGTDM
OGCOPRD	Crude production by oil category	MMbbl/day	10 OGSM reporting regions	Industrial
OGCOPRDGOM	Gulf of Mexico crude oil production	MMbbl/day	Shallow and deep water regions	Industrial
OGCOWHP	Crude wellhead price by oil category	87$/bbl	10 OGSM reporting regions	Industrial
OGCNQPRD	Canadian production of oil and gas	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGCNPPRD	Canadian price of oil and gas	oil:87$/ bbl gas:87$/ BCF	Fuel (oil, gas)	NGTDM
OGCORSV	Crude reserves by oil category	Bbbl	5 crude production categories	Industrial
OGCRDSHR	Crude oil shares by OGSM region and crude type	percent	7 OLOGSS regions	PMM
OGDNGPRD	Dry gas production	BCF	57 Lower 48 onshore & 6 Lower 48 offshore districts	PMM
OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGELSHALE	Electricity consumed	Trillion Btu	NA	Industrial
OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGEORFTDRL	Total footage drilled from CO2 projects	feet	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORINJWLS	Number of injector wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORNEWWLS	Number of new wells drilled from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRD	EOR production from CO2 projects	Mbbl	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRDWLS	Number of producing wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEOYAD	Unproved Associated-Dissolved gas resources	TCF	6 Lower 48 onshore regions	Industrial
OGEOYRSVON	Lower 48 Onshore proved reserves by gas category	TCF	6 Lower 48 onshore regions 5 gas categories	Industrial
OGEOYINF	Inferred oil and conventional NA gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial

Variable Name	Description	Unit	Classification	Passed To Module
OGEOYRSV	Proved Crude oil and natural gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYUGR	Technically recoverable unconventional gas resources	TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYURR	Undiscovered technically recoverable oil and conventional NA gas resources	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGGROWFAC	Factor to reflect expected future cons growth		NA	NGTDM
OGJOBS			NA	Macro
OGNGLAK	Natural Gas Liquids from Alaska	Mbbl/day	NA	PMM
OGNGPRD	Natural Gas production by gas category	TCF	10 OGSM reporting regions	Industrial
OGNGPRDGOM	Gulf of Mexico Natural Gas production	TCF	Shallow and deep water regions	Industrial
OGNGRSV	Natural gas reserves by gas category	TCF	12 oil and gas categories	Industrial
OGNGWHP	Natural gas wellhead price by gas category	87$/MCF	10 OGSM reporting regions	Industrial
OGNOWELL	Wells completed	wells	NA	Industrial
OGPCRWHP	Crude average wellhead price	87$/bbl	NA	Industrial
OGPNGEXP	NG export price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPNGWHP	Natural gas average wellhead price	87$/MCF	NA	Industrial
OGPPNGIMP	NG import price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPRCEXP	Adjusted price to reflect different expectation		NA	NGTDM
OGPRCOAK	Alaskan crude oil production	Mbbl	3 Alaska regions	NGTDM
OGPRDADOF	Offshore AD gas production	BCF	3 Lower 48 offshore regions	NGTDM
OGPRDADON	Onshore AD gas production	BCF	17 OGSM/NGTDM regions	NGTDM
OGPRDUGR	Lower 48 unconventional natural gas production	BCF	6 Lower 48 regions and 3 unconventional gas types	NGTDM
OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM
OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGQCRREP	Crude production by oil category	MMbbl	5 crude production categories	PMM
OGQCRRSV	Crude reserves	Bbbl	NA	Industrial
OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM

Variable Name	Description	Unit	Classification	Passed To Module
OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGQNGREP	Natural gas production by gas category	TCF	12 oil and gas categories	NGTDM
OGQNGRSV	Natural gas reserves	TCF	NA	Industrial
OGRADNGOF	Non Associated dry gas reserve additions, offshore	BCF	3 Lower 48 offshore regions	NGTDM
OGRADNGON	Non Associated dry gas reserve additions, onshore	BCF	17 OGSM/NGTDM regions	NGTDM
OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM
OGSHALENG	Gas produced	BCF	NA	NGTDM
OGTAXPREM	Canadian tax premium	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGTECHON	Technology factors	BCF	3 cost categories, 6 fuel types	Industrial
OGWPTDM	Natural Gas wellhead price	87$/MCF	17 OGSM/NGTDM regions	NGTDM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

CP13-25
CP13-27

ORIGINAL

March 3, 2014

Kimberly D. Bose,
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 204268

RE: Cameron LNG, LLC and Cameron Interstate Pipeline Draft Environmental Impact Statement (DEIS)

Dear Ms. Bose:

In accordance with our responsibilities under Section 309 of the Clean Air Act (CAA), the National Environmental Policy Act (NEPA), and the Council on Environmental Quality (CEQ) regulations for implementing NEPA, the U.S. Environmental Protection Agency (EPA) Region 6 office in Dallas, Texas, has completed its review of the Draft Environmental Impact Statement (DEIS) prepared by the Federal Energy Regulatory Commission (FERC) for the Cameron Liquefaction Project (Project), proposed by Cameron LNG, LLC and Cameron Interstate Pipeline, LLC (collectively Cameron). Cameron requests authorization to export 12 million tons of liquefied natural gas (LNG) per year from its terminal in Cameron and Calcasieu Parishes, Louisiana.

Based on our review, we have rated the DEIS as "Environmental Concerns - Insufficient Information" (EC-2); additional information on EPA's rating system can be found at http://www.epa.gov/compliance/nepa/comments/ratings.html. We have enclosed detailed comments that identify our concerns and recommendations for additional analysis for the Final EIS (FEIS).

EPA appreciates the opportunity to review the DEIS. Please send our office one copy of the FEIS when it is filed using our *e-NEPA Electronic Filing System* at http://www.epa.gov/compliance/nepa/submiteis/index.html. Please note that a copy of this letter will be published on our website, http://www.epa.gov/compliance/nepa/eisdata.html, in order to fulfill our responsibility under Section 309 of the CAA to inform the public of our views on the proposed Federal action. If you have any questions or concerns, please contact Rhonda Smith or Michael Jansky of my staff at (214) 665-8006 or (214) 665-7438 or via email at smith.rhonda@epa.gov or jansky.michael@epa.gov respectively for assistance.

Sincerely,

Debra A. Griffin
Associate Director
Compliance Assurance and
Enforcement Division

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FEDERAL ENERGY
REGULATORY COMMISSION

Enclosure

DETAILED COMMENTS
ON THE FEDERAL ENERGY REGULATORY COMMISSION
CAMERON LNG, LLC AND CAMERON INTERSTATE PIPELINE, LLC
DRAFT ENVIRONMENTAL IMPACT STATEMENT

BACKGROUND

The Federal Energy Regulatory Commission (FERC) prepared this Draft Environmental Impact Statement (DEIS) to assess the environmental impacts associated with the construction of facilities proposed by Cameron LNG, LLC and Cameron Interstate Pipeline, LLC. This project is referred to as the Cameron Liquefaction Project (Project) and consists of the Cameron LNG Terminal Expansion (Terminal Expansion) and the Cameron Pipeline Expansion (Pipeline Expansion).

Cameron proposes to construct and operate onshore natural gas liquefaction and associated facilities to allow the export of liquefied natural gas (LNG), and to construct, own, operate, and maintain a new interstate natural gas pipeline, compressor station, and ancillary facilities in Louisiana.

PROPOSED ACTION

According to Cameron, the Project would transport and liquefy domestic natural gas into LNG for export, and deliver competitively-priced LNG to foreign markets. Cameron designed its project to meet each of the following purposes:

- enable bi-directional flow of natural gas along the Cameron Interstate Pipeline system and allow natural gas to be received from five pipeline interconnections;
- allow natural gas to be received by pipeline at the expanded LNG Terminal that would be treated, liquefied, stored, and loaded from LNG storage tanks into vessels berthed at the terminal's existing marine facility;
- preserve the import and re-gasification capabilities of the Cameron LNG Terminal; and
- preserve export capability of foreign-sourced LNG at the Cameron LNG Terminal.

Terminal Expansion

Cameron LNG would construct the Terminal Expansion on a 502-acre site between Louisiana State Highway 27 (LA-27) and the Calcasieu Ship Channel, about 2 miles north of the community of Hackberry, Louisiana. The proposed site is north of and partially within the existing terminal fence line in Cameron and Calcasieu Parishes, Louisiana. The Terminal Expansion would include the following key facilities:

- three separate systems that liquefy natural gas, each capable of producing 4 million metric tons per year of LNG for export;
- a 160,000-cubic-meter, full-containment LNG storage tank;
- refrigerant make-up and condensate product storage tanks;

- a truck loading/unloading area;
- a marine work dock for delivery of equipment and construction materials;
- utilities and associated systems; and
- minor modifications to existing terminal facilities.

Pipeline Expansion

Cameron proposes to construct and operate about 21 miles of 42-inch-diameter pipeline, a compressor station (Holbrook Compressor Station) totaling about 56,820 horsepower, and associated facilities in Cameron, Calcasieu, and Beauregard Parishes, Louisiana. The pipeline would extend from an existing Cameron Interstate Pipeline interconnection at the Florida Gas Transmission (FGT) pipeline to a new interconnection with Trunkline Gas Pipeline (Trunkline). Cameron would construct and operate a new interconnection with Trunkline; modify existing interconnections and metering facilities with the Transcontinental Gas Pipeline Corporation, Texas Eastern Transmission Company, FGT, and Tennessee Gas Pipeline systems; and construct and operate associated facilities, including metering facilities, pig receivers and launchers,[2] and mainline valves.

COMMENTS

The following comments are offered for FERC's consideration in preparation of the Final EIS (FEIS).

Environmental Justice

While EPA recognizes that FERC is not one of the agencies specified in Executive Order 12898 - Environmental Justice for Low Income and Minority Populations, we appreciate that it is FERC's practice to address environmental justice in its NEPA documents. In this case, however, the DEIS does not provide any analysis to determine whether there are potentially affected low-income or minority populations, and consequently, there is no information provided to determine whether there may be disproportionate high and adverse human health or environmental effects on minority or low-income populations as result of the proposed action.

Recommendation:

EPA recommends that the Final EIS (FEIS) analyze the potential for environmental justice issues, using the methods outlined in the Council on Environmental Quality's guidance ("Environmental Justice: Guidance under the National Environmental Policy Act," December 1977), available at http://energy.gov/nepa/downloads/environmental-justice-guidance-under-nepa. The FEIS should determine whether minority and low-income populations are present that have the potential to be affected by the proposed project. As part of that analysis, for example, we recommend that the FEIS include a comparison of the demographics of the project area and suitable reference areas, like Cameron, Calcasieu and Beauregard Parishes. If potential environmental justice populations are identified, then the FEIS should determine whether there may be disproportionate high and adverse human health or environmental impacts on these populations, and measures to address those impacts should be considered.

Air Quality

PM_{10} Emissions and Fugitive Dust Control

EPA believes it is especially important that mitigation measures include the use of best management practices for PM_{10} and fugitive dust control (e.g., gravel roads, soil wetting practices, limiting access, traffic and speed reduction). In order to further reduce potential air quality impacts, the FEIS should include a detailed Construction Emissions Mitigation Plan or more fully discuss how the existing Fugitive Dust Control Plan for construction of the project is sufficient.

Section 4.11.1 – Air Quality, Pages 4-121 and 4-122:

This section states that once the construction phase in completed, the fugitive dust and emissions would subside and would be limited. Additionally, the section states that mitigation measures employed by Cameron LNG would meet all Louisiana Department of Environmental Quality (LDEQ) requirements for construction-related vehicle exhaust emissions. EPA recommends that, in addition to all applicable local, state, or federal requirements, the following mitigation measures be included (as applicable) in a construction emissions mitigation plan or similar document in order to reduce air quality impacts associated with emissions of NOx, CO, CO_2, PM, SO_2, and other pollutants from construction-related activities:

The FEIS should more fully discuss specific actions including dust ordinances on the parish level, educational outreach tools, and tools to minimize the residents' exposure to PM_{10}, as applicable. In addition to measures included in the DEIS and all applicable local, state, or federal requirements, the EPA recommends that the following mitigation measures (as applicable) be included in the Plan in order to reduce impacts associated with emissions of PM, and other pollutants from any planned structural and non-structural activities, and possible future modifications to the roadway system:

Recommendations:

- Construction Emissions Mitigation Plan – The FEIS should include a draft Construction Emissions Mitigation Plan and ultimately adopt this plan in the Record of Decision. In addition to all applicable local, state, or federal requirements, we recommend the following control measures (Fugitive Dust, Mobile and Stationary Source and Administrative) be included (as applicable) in the Construction Emissions Mitigation Plan in order to reduce impacts associated with emissions of particulate matter and other pollutants from construction-related activities:
    - Fugitive Dust Source Controls: The FEIS should identify the need for a Fugitive Dust Control Plan to reduce Particulate Matter 10 and Fine

Particulate Matter 2.5 emissions during construction and operations. We recommend that the plan include these general commitments:

- Stabilize heavily used unpaved construction roads with a non toxic soil stabilizer or soil weighting agent that will not result in loss of vegetation, or increase other environmental impacts.
- During grading, use water, as necessary, on disturbed areas in construction sites to control visible plumes.
- Vehicle Speed
    - Limit speeds to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.
    - Limit speeds to 10 miles per hour or less on unpaved areas within construction sites on un-stabilized (and unpaved) roads.
    - Post visible speed limit signs at construction site entrances.
- Inspect and wash construction equipment vehicle tires, as necessary, so they are free of dirt before entering paved roadways, if applicable.
- Provide gravel ramps of at least 20 feet in length at tire washing/cleaning stations, and ensure construction vehicles exit construction sites through treated entrance roadways, unless an alternative route has been approved by appropriate lead agencies, if applicable.
- Use sandbags or equivalent effective measures to prevent run off to roadways in construction areas adjacent to paved roadways. Ensure consistency with the project's Storm Water Pollution Prevention Plan, if such a plan is required for the project.
- Sweep the first 500 feet of paved roads exiting construction sites, other unpaved roads en route from the construction site, or construction staging areas whenever dirt or runoff from construction activity is visible on paved roads, or at least twice daily (less during periods of precipitation).
- Stabilize disturbed soils (after active construction activities are completed) with a non toxic soil stabilizer, soil weighting agent, or other approved soil stabilizing method.
- Cover or treat soil storage piles with appropriate dust suppressant compounds and disturbed areas that remain inactive for longer than 10 days. Provide vehicles (used to transport solid bulk material on public roadways and that have potential to cause visible emissions) with covers. Alternatively, sufficiently wet and load materials onto the trucks in a manner to provide at least one foot of freeboard.
- Use wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) where soils are disturbed in construction, access and maintenance routes, and materials stock pile areas. Keep related windbreaks in place until the soil is stabilized or permanently covered with vegetation.

- If practicable, lease new, clean equipment meeting the most stringent of applicable Federal[1]or State Standards. In general, commit to the best available emissions control technology. Tier 4 engines should be
- used for project construction equipment to the maximum extent feasible.
- Where Tier 4 engines are not available, use construction diesel engines with a rating of 50 hp or higher that meet, at a minimum, the Tier 3 Ignition Engines[2], unless such engines are not available.
- Where Tier 3 engine is not available for off road equipment larger than 100 hp, use a Tier 2 engine, or an engine equipped with retrofit controls to reduce
- exhaust emissions of nitrogen oxides and diesel particulate matter to no more than Tier 2 levels.
- Consider using electric vehicles, natural gas, biodiesel, or other alternative fuels during construction and operation phases to reduce the project's criteria and greenhouse gas emissions.
- Plan construction scheduling to minimize vehicle trips.
- Limit idling of heavy equipment to less than 5 minutes and verify through unscheduled inspections.
- Maintain and tune engines per manufacturer's specifications to perform at EPA certification levels, prevent tampering, and conduct unscheduled inspections to ensure these measures are followed.

o <u>Administrative controls</u>:

- Develop a construction traffic and parking management plan that maintains traffic flow and plan construction to minimize vehicle trips.
- Identify any sensitive receptors in the project area, such as children, elderly, and the infirm, and specify the means by which impacts to these populations will be minimized (e.g. locate construction equipment and staging zones away from sensitive receptors and building air intakes).
- Include provisions for monitoring fugitive dust in the fugitive dust control plan and initiate increased mitigation measures to abate any visible dust plumes.

Greenhouse Gas (GHG) Emissions

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[1] EPA's website for nonroad mobile sources is http://www.epa.gov/nonroad/.

The DEIS provides information on the potential greenhouse gas emissions associated with the terminal and pipeline expansion. However, the DEIS does not provide an assessment of the lifecycle GHG emissions associated with the proposed action.

Recommendation:

We recommend that FERC establish reasonable spatial and temporal boundaries for the analysis of GHG emissions, and that the FEIS quantify and consider the lifecycle GHG emissions associated with the proposed action. The methodologies for conducting that analysis are available and well developed; FERC could draw on good examples of lifecycle GHG emissions done in NEPA analyses by other federal agencies.

Indirect Effects

In addition to considering the direct impacts of a proposed action, NEPA requires that agencies also consider indirect effects where there is a reasonably close causal relationship between the action and the environmental effect. With regard to LNG export terminals, we note that the Energy Information Administration's overall analysis of natural gas exports found that natural gas markets in the US balance in response to increased natural gas exports largely through increased natural gas production (http://energy.gov/fe/services/natural-gas-regulation/lng-export-study). However, the DEIS does not consider the potential for increased natural gas production as a result of the proposed export terminal, or the potential for environmental impacts associated with potential increases in natural gas production.

Recommendation:

We recommend the FEIS consider the extent to which implementation of the proposed project could increase the demand for domestic natural gas extraction, as well as potential environmental impacts associated with the potential increased production of natural gas.

Wetlands

Jurisdictional Wetlands

The DEIS states that 99.2 acres of wetlands on the site are jurisdictional under the Clean Water Act Section 404. However, a revised Jurisdictional Determination (JD) for the terminal site was issued by the U.S. Army Corps of Engineers New Orleans District on December 31, 2013. According to the revised JD, there are 335 acres of jurisdictional wetlands located on the property. Construction would impact approximately 213.5 acres of jurisdictional wetlands.

Recommendation:

The FEIS should be revised to accurately quantify the impacts to jurisdictional wetlands and waters of the U.S.

Compensatory Mitigation for Wetland Impacts

Cameron LNG has proposed to mitigate for impacts to wetlands by using dredged material generated by construction of the work dock and maintenance dredging at the existing terminal berthing area to fill shallow open water and create tidal emergent marsh habitat. The DEIS states that approximately 129 acres of open water would be converted to marsh habitat as compensatory mitigation for 99.2 acres of wetland impacts.

Recommendations:

The FEIS should include a mitigation plan for all impacts to jurisdictional wetlands.

EPA requests that the FEIS include a map that identifies proposed mitigation areas, and cross-sections and target elevations for the created tidal marsh based on adjacent healthy reference marsh.

The FEIS should include a mitigation work plan and construction schedule, performance standards, monitoring and reporting plan, long-term and adaptive management plans, and long-term protection measures and financial assurances for this project.

EPA suggests that a wetland functional assessment be performed for both the impact and mitigation sites to determine that the proposed project would not result in a net loss of wetland functions in the project watershed.

EPA suggests that mitigation be conducted prior to or concurrently with the project impacts to reduce temporal loss of wetland functions.

Document Content(s)

PF13-1-000

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April 4, 2013

ORIGINAL

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Subject: Detailed Scoping Comments for Preparing an Environmental Impact Statement (EIS) for the Proposed Excelerate Liquefaction Solutions, LLC and Lavaca Bay Pipeline System, LLC, Liquefied Natural Gas (LNG) Export Project, located in Calhoun and Jackson Counties, Texas

Dear Ms. Bose:

The Region 6 office of the U.S. Environmental Protection Agency (EPA) has reviewed the March 12, 2013, NOI to prepare an EIS for the proposed Excelerate Liquefaction Solutions, LLC and Lavaca Bay Pipeline System, LLC, LNG Export Project, located in Calhoun and Jackson counties, Texas. Our comments are provided pursuant to the National Environmental Policy Act (NEPA), Council on Environmental Quality (CEQ) regulations (40 CFR Parts 1500-1508) and Section 309 of the Clean Air Act.

To assist in the scoping process for this project, we have identified several issues for your attention in the preparation of the EIS and enclosed detailed scoping comments for your consideration. EPA is most concerned about the following issues: mitigation, alternative development, impacts to water and biological resources, invasive species management, habitat protection, air quality, Greenhouse Gas (GHG) and National Pollutant Discharge Elimination System (NPDES) permitting, cumulative impacts, climate change, and environmental justice.

We appreciate the opportunity to review this NOI and are available to discuss our comments. Please send one hard copy of the Draft EIS and four CD ROM copies to this office when completed and submitted for public comment. If you have any questions, please contact Rhonda Smith or Michael Jansky of my staff at (214) 665-8006 or (214) 665-7451; or by e-mail at smith.rhonda@epa.gov or jansky.michael@epa.gov, respectively. You may now electronically file you EIS using our *e-NEPA Electronic Filing* by linking to EPA's web site at http://www.epa.gov/compliance/nepa/submiteis/index.html.

Sincerely,

Debra A. Griffin

Debra A. Griffin
Associate Director
Compliance Assurance and
Enforcement Division

Enclosure

Internet Address (URL) ● http://www.epa.gov/region6
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DETAILED SCOPING COMMENTS
ON THE
NOTICE OF INTENT (NOI)
FOR THE FEDERAL ENERGY REGULATORY COMMISSION (FERC)
TO PREPARE AN
ENVIRONMENTAL IMPACT STATEMENT (EIS)
FOR THE PROPOSED
EXCELERATE LIQUEFACTION SOLUTIONS (ELS)
LAVACA BAY PIPELINE SYSTEM
CALHOUN AND JACKSON COUNTIES, TEXAS

Proposed Action

In compliance with the National Environmental Policy Act of 1969 (NEPA), as amended, the Federal Energy and Regulatory Commission (FERC) intends to prepare an Environmental Impact Statement (EIS) analyzing the impacts of the proposed Excelerate Liquefaction Solutions, LLC and Lavaca Bay Pipeline System, LLC, Liquefied Natural Gas (LNG) Export Project located in Calhoun and Jackson counties, Texas. This EIS will be used by FERC in its decision making process to determine whether the project is in the public interest. FERC will serve as the lead Federal agency under the NEPA process and is responsible for the preparation of the EIS.

Project Components

ELS plans to develop, construct, and operate LNG terminal facilities that include two purpose-built floating liquefaction, storage, and offloading units (FLSOs) and a 29-mile long pipeline header system to transport natural gas from existing pipeline systems to the LNG terminal facilities. The project would be constructed in two phases:

Phase 1 would include a single FLSO with a storage capacity of about 250,000 cubic meters (m3) of LNG and the capacity to produce up to four million tons per annum (MTPA), nominally of natural gas. Phase 2 would include facilities to support a second FLSO that would double the production to eight MTPA, nominally.

The Lavaca Bay LNG Project would consist of the following facilities:

- Two double-hulled, permanently moored, FLSOs, each containing 10 LNG storage tanks, four 1 MTPA system trains for liquefaction, centrifugal refrigerant compressors, and associated infrastructure;

- Mooring structures and fenders to provide support for the FLSOs and LNG carriers;

- A new 2,218-foot-diameter turning basin dredged to a depth of 45.5 feet below the site datum located adjacent to the existing Matagorda Ship Channel;

- Two berthing pockets each 450 feet wide by 1,310 feet long dredged to a depth of 60.5 feet below the site datum; and

- A 3,200-foot-long jetty with two reinforced concrete decked piers located adjacent to the turning basins. ELS would deepen and widen the Matagorda Ship Channel to a depth of 44 feet mean low tide and a channel bottom width up to 300 feet.

- A pig 1 launcher and receiver;

- Feed gas metering, compression, and pre-treatment;

- An inlet bulk separator;

- A condensate storage tank;

- A power generation system;

- A cooling water system and instrument air package;

- A cold vent/ground flare;

- A fire water system and water treatment plant; and

- Support buildings, including offices, control room, warehouse, and shop.

- A 29-mile-long, 42-inch-diameter natural gas pipeline extending northward from the shore side facilities to nine natural gas interconnects southwest of Edna, Texas.

The planned LNG terminal facilities (i.e., marine and shore side facilities) would be constructed on about 85 acres of land. Of this amount, about 45 acres includes existing uplands and the remaining 40 acres would be created using dredge spoil from construction of the turning basin and two berthing pockets. Construction of the pipeline header system would require about 327 acres of land for construction and 164 acres for operation. The Project would also require approximately 150 additional acres for temporary use for construction laydown/staging areas and parking areas.

The following detailed comments are offered for your consideration and incorporation into your Draft EIS (DEIS).

DETAILED COMMENTS

Statement of Purpose and Need

The DEIS should clearly identify the underlying purpose and need to which the FERC is responding in proposing the alternatives (40 CFR 1502.13). The purpose of the proposed action is typically the specific objectives of the activity, while the need for the proposed action may be to eliminate a broader underlying problem or take advantage of an opportunity.

Recommendation:
The purpose and need should be a clear, objective statement of the rationale for the proposed project. The DEIS should discuss the proposed project in the context of the LNG supply and the need for an additional export capabilities.

Alternatives Analysis

The National Environmental Policy Act (NEPA) requires evaluation of reasonable alternatives, including those that may not be within the jurisdiction of the lead agency (40 CFR Section 1502.14(c)). A robust range of alternatives will include options for avoiding significant environmental impacts. The DEIS should provide a clear discussion of the reasons for the elimination of alternatives which are not evaluated in detail.

The environmental impacts of the proposal and alternatives should be presented in comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decision maker and the public (40 CFR 1502.14). The potential environmental impacts of each alternative should be quantified to the greatest extent possible (e.g., acres of bay bottom impacted, tons per year of emissions produced).

Recommendations:

The DEIS should describe how each alternative was developed, how it addresses each project objective, and how it will be implemented. The alternatives analysis should include a discussion of alternatives. The DEIS should clearly describe the rationale used to determine whether impacts of an alternative are significant or not. The DEIS should describe the methodology and criteria used for determining project siting. Thresholds of significance should be determined by considering the context and intensity of an action and its effects (40 CFR 1508.27).

Water Supply and Water Quality

Public drinking water supplies and/or their source areas often exist in many watersheds. Source water is water from streams, rivers, lakes, springs, and aquifers that is used as a supply of drinking water. Source water areas are delineated and mapped by the state for each federally-regulated public water system. The 1996 amendments to the Safe Drinking Water Act require federal agencies to protect sources of drinking water for communities. The DEIS should address the potential effects of project discharges, if any, on surface water quality. Specific discharges should be identified and potential effects of discharges on designated beneficial uses of affected waters should be analyzed.

Recommendations:

The DEIS should address the potential effects of project discharges, if any, on surface water quality. Specific discharges should be identified and potential effects of discharges on designated beneficial uses of affected waters should be analyzed.

The DEIS should describe water reliability for the proposed project and clarify how existing and/or proposed sources may be affected by climate change. At a minimum, the EPA expects a qualitative discussion of impacts to water supply and the adaptability of the project to these changes.

Stormwater Considerations

The DEIS should describe the original (natural) drainage patterns in the project locale, as well as the drainage patterns of the area during project operations. Also, the DEIS should identify whether any components of the proposed project are within a 50 or 100-year floodplain. The DEIS should note that, under the Federal Clean Water Act, any construction project disturbing a land area of one or more acres requires a construction stormwater discharge permit.

Recommendations:

The DEIS should document the project's consistency with applicable stormwater permitting requirements. Requirements of a stormwater pollution prevention plan should be reflected as appropriate in the DEIS.

The DEIS should discuss specific mitigation measures that may be necessary or beneficial in reducing adverse impacts to water quality and aquatic resources.

Geographic Extent of Waters of the United States

The project applicant should coordinate with the U.S. Army Corps of Engineers to determine if the proposed project requires a Section 404 permit under the Clean Water Act (CWA). Section 404 regulates the discharge of dredged or fill material into waters of the United States (WUS), including wetlands and other *special aquatic sites*.

EPA recommends that FERC include a jurisdictional delineation for all WUS, including ephemeral drainages, in accordance with the 1987 *Corps of Engineers Wetlands Delineation Manual* and the December 2006 *Atlantic and Gulf Coast Region Interim Regional Supplement to the Corps of Engineers Wetland Delineation Manual:* A jurisdictional delineation will confirm the presence or absence of WUS in the project area and help determine whether or not the proposed project would require a Section 404 permit.

If a permit is required, the EPA will review the project for compliance with *Federal Guidelines for Specification of Disposal Sites for Dredged or Fill Materials* (40 CFR 230), promulgated pursuant to Section 404(b)(1) of the CWA. Pursuant to 40 CFR 230, any permitted discharge into WUS must be the *least environmentally damaging practicable alternative* available to achieve the project purpose. The DEIS should include an evaluation of the project alternatives in this context in order to demonstrate the project's compliance with the 404(b)(1) Guidelines. If, under the proposed project, dredged or fill material would be discharged into WUS, the DEIS should discuss alternatives to avoid those discharges.

Recommendation:

The FERC should consult with the USACE to determine if there are jurisdictional waters of the U.S. present at the project site. If jurisdictional WUS are determined to be on the project site, the DEIS should include a final determination of the extent of WUS at the project site and address any other relevant requirements, pursuant to the CWA Section 404 (b)(1).

Clean Water Act (CWA) Section 303(d)

The CWA requires States to develop a list of impaired waters that do not meet water quality standards, establish priority rankings, and develop action plans, called Total Maximum Daily Loads (TMDL), to improve water quality. The DEIS should provide information on CWA Section 303(d) impaired waters in the project area, if any, and efforts to develop and revise TMDLs. The DEIS should describe existing restoration and enhancement efforts for those waters, and any mitigation measures that will be implemented to avoid further degradation of impaired waters.

Recommendation:

The DEIS should provide information on CWA Section 303(d) impaired waters in the project area, if any, and efforts to develop and revise TMDLs. The DEIS should describe existing restoration and enhancement efforts for those waters, how the proposed project will coordinate with on-going protection efforts, and any mitigation measures that will be implemented to avoid further degradation of impaired waters.

Biological Resources, Habitat and Wildlife

The DEIS should identify all petitioned and listed threatened and endangered species and critical habitat that might occur within the project area, including any areas. The DEIS should identify which species or critical habitat might be directly, indirectly, or cumulatively affected by each alternative and describe possible mitigation for each of the species. EPA recommends that the FERC consultation with the U.S. Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS) under Section 7 of the Endangered Species Act include consideration of all impacts related to EPA's Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting action and/or National Pollutant Discharge Elimination System (NPDES) permitting actions. We also recommend that the FERC coordinate across field offices and with USFWS, NMFS, and the Texas Parks and Wildlife Department (TPWD) to ensure that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

Recommendations:

EPA recommends that FERC coordinate across field offices and with the USFWS, NMFS and TPWD to ensure that current and consistent surveying, monitoring, and reporting protocols are applied in protection and mitigation efforts.

Analysis of impacts and mitigation on covered species should include:

- Baseline conditions of habitats and populations of the covered species.
- A clear description of how avoidance, mitigation and conservation measures will protect and encourage the recovery of the covered species and their habitats in the project area.
- Monitoring, reporting and adaptive management efforts to ensure species and habitat conservation effectiveness.
- A discussion of how the projects potential impacts such as air emissions and/or wastewater discharges may impact species.

If the applicant is to acquire compensation lands, the location(s) and management plans for these lands should be discussed in the DEIS.

Recommendations:

Incorporate, into the DEIS, information on the compensatory mitigation proposals (including quantification of acreages, estimates of species protected, costs to acquire compensatory lands, etc.) for unavoidable impacts to WUS and biological resources.

Identify compensatory mitigation lands or quantify, in the DEIS, available lands for compensatory habitat mitigation for this project, as well as reasonably foreseeable projects in the area. Specify, in the DEIS, provisions that will ensure habitat selected for compensatory mitigation will be protected in perpetuity.

Incorporate, into the DEIS, mitigation, monitoring, and reporting measures that result from consultation with the USFWS or NMFS that incorporate recently released guidance to avoid and minimize adverse effects to sensitive biological resources.

The DEIS should describe the potential for habitat fragmentation and obstructions for wildlife movement from the construction of this project and other projects in the area.

Discuss the need for monitoring, mitigation, and if applicable, translocation management plans for the sensitive biological resources, approved by the USFWS, NMFS and the biological resource management agencies.

EPA is also concerned about the potential impact of construction, installation, and maintenance activities (deep trenching, grading, filling, and fencing) on habitat. The DEIS should describe the extent of these activities and the associated impacts on habitat and threatened and endangered species, including all interrelated and interdependent facilities. We encourage habitat conservation alternatives that avoid and protect high value habitat and create or preserve linkages between habitat areas to better conserve the covered species.

Recommendations:

The DEIS should describe the extent of potential impacts from construction, installation, and maintenance activities, including all interrelated and interdependent facilities.

The DEIS should describe the ROW vegetation management techniques to be used and potential associated environmental impacts, especially if mechanical methods or herbicides are to be used.

The DEIS should indicate the location of important marine and wildlife habitat areas. The DEIS should describe what measures will be taken to protect important wildlife habitat areas and to preserve linkages between them.

The DEIS should provide detailed information on any proposed fencing design and placement, and its potential effects on drainage systems on the project site. Fencing proposed for this project should meet appropriate hydrologic, wildlife protection and movement, and security performance standards.

Invasive Species

Human actions are the primary means of invasive species introductions. Pipeline construction causes disturbance of ROW soils and vegetation through the movement of people and vehicles along the ROW, access roads, and lay down areas. These activities can contribute to the spread of invasive species. Parts of plants, seeds, and root stocks can contaminate construction equipment and essentially "seed" invasive species wherever the vehicle travels. Invasive species infestations can also occur during periodic ROW maintenance activities especially if these activities include mowing and clearing of vegetation. Once introduced, invasive species will likely spread and impact adjacent properties with the appropriate habitat.

Executive Order 13112, *Invasive Species* (February 3, 1999), mandates that federal agencies take actions to prevent the introduction of invasive species, provide for their control, and minimize the economic, ecological, and human health impacts that invasive species cause. Executive Order 13112 also calls for the restoration of native plants and tree species. If the proposed project will entail new landscaping, the DEIS should describe how the project will meet the requirements of Executive Order 13112.

In addition, we encourage alternative management practices that limit herbicide use (as a last resort), focusing instead on other methods to limit invasive species vegetation and decrease fire risk. Possible alternatives include mowing and weed control fabric, which may need a layer of soil to prevent degradation due to ultraviolet light.

Recommendations:

The DEIS should describe the invasive plant management plan used to monitor and control noxious weeds. If herbicides or pesticides will be used to manage vegetation, the DEIS should disclose the projected quantities and types of chemicals. The invasive plant management plan should identify methods that can be used to limit the introduction and spread of invasive species during and post-construction. These measures can include marking and avoidance of invasives, timing construction activities during periods that would minimize their spread, proper cleaning of equipment, and proper disposal of woody material removed from the ROW.

Because construction measures may not be completely effective in controlling the introduction and spread of invasives, the DEIS should describe post-construction activities that will be required such as surveying for invasive species following restoration of the construction site and measures that will be taken if infestations are found.

Air Quality

The DEIS should provide a detailed discussion of ambient air conditions (baseline or existing conditions), National Ambient Air Quality Standards (NAAQS) and non-NAAQS pollutants, criteria pollutant nonattainment areas, and potential air quality impacts of the proposed project (including cumulative and indirect impacts). Such an evaluation is necessary to understand the potential impacts from temporary, long-term, or cumulative degradation of air quality.

The DEIS should describe and estimate air emissions from potential construction and maintenance activities, as well as proposed mitigation measures to minimize those emissions. EPA recommends an evaluation of the following measures to reduce emissions of criteria air pollutants and hazardous air pollutants (air toxics).

Recommendations:

- *Existing Conditions* – The DEIS should provide a detailed discussion of ambient air conditions, National Ambient Air Quality Standards, and criteria pollutant nonattainment areas in the vicinity of the project.

- *Quantify Emissions* – The DEIS should estimate emissions of criteria and hazardous air pollutants (air toxics) from the proposed project and discuss the timeframe for release of these emissions over the lifespan of the project. The EIS should describe and estimate emissions from potential construction activities, as well as proposed mitigation measures to minimize these emissions.

- *Specify Emission Sources* – The DEIS should specify all emission sources by pollutant from mobile sources (on and off-road), stationary sources (including portable and temporary emission units), fugitive emission sources, area sources, and ground disturbance. This source specific information should be used to identify appropriate mitigation measures and areas in need of the greatest attention.

- *Construction Emissions Mitigation Plan* – The DEIS should include a draft Construction Emissions Mitigation Plan and ultimately adopt this plan in the Record of Decision. In addition to all applicable local, state, or federal requirements, we recommend the following control measures (Fugitive Dust, Mobile and Stationary Source and Administrative) be included in the Construction Emissions Mitigation Plan in order to reduce impacts associated with emissions of particulate matter and other toxics from construction-related activities:

- <u>Fugitive Dust Source Controls</u>: The DEIS should identify the need for a Fugitive Dust Control Plan to reduce Particulate Matter 10 and Fine Particulate Matter 2.5 emissions during construction and operations. We recommend that the plan include these general commitments:
  - Stabilize heavily used unpaved construction roads with a non-toxic soil stabilizer or soil weighting agent that will not result in loss of vegetation, or increase other environmental impacts.
  - During grading, use water, as necessary, on disturbed areas in construction sites to control visible plumes.
  - Vehicle Speed
    - Limit speeds to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.
    - Limit speeds to 10 miles per hour or less on unpaved areas within construction sites on un-stabilized (and unpaved) roads.
    - Post visible speed limit signs at construction site entrances.
  - Inspect and wash construction equipment vehicle tires, as necessary, so they are free of dirt before entering paved roadways, if applicable.
  - Provide gravel ramps of at least 20 feet in length at tire washing/cleaning stations, and ensure construction vehicles exit construction sites through treated entrance roadways, unless an alternative route has been approved by appropriate lead agencies, if applicable.
  - Use sandbags or equivalent effective measures to prevent run-off to roadways in construction areas adjacent to paved roadways. Ensure consistency with the project's Storm Water Pollution Prevention Plan, if such a plan is required for the project
  - Sweep the first 500 feet of paved roads exiting construction sites, other unpaved roads en route from the construction site, or construction staging areas whenever dirt or runoff from construction activity is visible on paved roads, or at least twice daily (less during periods of precipitation).
  - Stabilize disturbed soils (after active construction activities are completed) with a non-toxic soil stabilizer, soil weighting agent, or other approved soil stabilizing method.
  - Cover or treat soil storage piles with appropriate dust suppressant compounds and disturbed areas that remain inactive for longer than 10 days. Provide vehicles (used to transport solid bulk material on public roadways and that have potential to cause visible emissions) with covers. Alternatively, sufficiently wet and load materials onto the trucks in a manner to provide at least one foot of freeboard.

    - Use wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) where soils are disturbed in construction, access and maintenance routes, and materials stock pile areas. Keep related windbreaks in place until the soil is stabilized or permanently covered with vegetation.

- Mobile and Stationary Source Controls:
    - If practicable, lease new, clean equipment meeting the most stringent of applicable Federal[1] or State Standards[2]. In general, commit to the best available emissions control technology. Tier 4 engines should be used for project construction equipment to the maximum extent feasible[3].
    - Where Tier 4 engines are not available, use construction diesel engines with a rating of 50 hp or higher that meet, at a minimum, the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines[4], unless such engines are not available.
    - Where Tier 3 engine is not available for off-road equipment larger than 100 hp, use a Tier 2 engine, or an engine equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides and diesel particulate matter to no more than Tier 2 levels.
    - Consider using electric vehicles, natural gas, biodiesel, or other alternative fuels during construction and operation phases to reduce the project's criteria and greenhouse gas emissions.
    - Plan construction scheduling to minimize vehicle trips.
    - Limit idling of heavy equipment to less than 5 minutes and verify through unscheduled inspections.
    - Maintain and tune engines per manufacturer's specifications to perform at CARB and/or EPA certification levels, prevent tampering, and conduct unscheduled inspections to ensure these measures are followed.

- Administrative controls:
    - Develop a construction traffic and parking management plan that maintains traffic flow and plan construction to minimize vehicle trips.
    - Identify any sensitive receptors in the project area, such as children, elderly, and the infirm, and specify the means by which impacts to these populations will be minimized (e.g. locate construction equipment and staging zones away from sensitive receptors and building air intakes).

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[1] EPA's website for nonroad mobile sources is http://www.epa.gov/nonroad/.

[2] For California, see ARB emissions standards, see: http://www.arb.ca.gov/msprog/offroad/offroad.htm.

[3] Diesel engines < 25 hp rated power started phasing in Tier 4 Model Years in 2008. Larger Tier 4 diesel engines will be phased in depending on the rated power (e.g., 25 hp - <75 hp: 2013; 75 hp - < 175 hp: 2012-2013; 175 hp - < 750 hp: 2011 - 2013; and ≥ 750 hp 2011- 2015).

- Include provisions for monitoring fugitive dust in the fugitive dust control plan and initiate increased mitigation measures to abate any visible dust plumes.

Climate Change

Scientific evidence supports the concern that continued increases in greenhouse gas emissions resulting from human activities will contribute to climate change. Global warming is caused by emissions of carbon dioxide and other heat-trapping gases. On December 7, 2009, the EPA determined that Greenhouse Gases (GHG)s contribute to air pollution that "endangers public health and welfare" within the meaning of the Clean Air Act. Higher temperatures and increased winter rainfall will be accompanied by a reduction in snow pack, earlier snowmelts, and increased runoff. Some of the impacts, such as reduced groundwater discharge, and more frequent and severe drought conditions, may impact the proposed projects. The DEIS should consider how climate change could potentially influence the proposed project, specifically within sensitive areas, and assess how the projected impacts could be exacerbated by climate change.

Recommendation:

The DEIS should consider how climate change could potentially influence the proposed project, specifically within sensitive areas. Also, the DEIS should assess how the projected impacts could be exacerbated by climate change, and strategies for climate change adaptation planning. For example, measures for climate change adaptation should consider potentially increased drainage needs.

Greenhouse Gas (GHG) Emissions

On February 18, 2010, the CEQ issued draft guidance to Federal Agencies on analyzing the effects of Greenhouse Gas (GHG) emissions and climate change when describing the environmental effects of a proposed agency action in accordance with NEPA CEQ's draft guidance defines GHG emissions in accordance with Section 19(i) of *E.O. 13514 Federal Leadership in Environment, Energy, and Economic Performance (October 5, 2009)* to include carbon dioxide ($C0_2$), methane (CH_4), nitrous oxide (N_20), hydrofluorcarbon (HFCs), perfluorcarbon (PFCs), and sulfurhexafluoride (SF_6). Because CO_2 is the reference gas for climate change based on their potential to absorb heat in the atmosphere, measures of non-$C0_2$ GHGs should be reflected as CO_2-equivalent (COre) values. The EPA supports evaluation and disclosure of GHG emissions and climate change effects resulting from the proposed project during all project phases, including (I) pre-construction (e.g., transportation, mobilization, and staging), (2) construction, (3) operation, (4) maintenance, and (5) decommissioning. We recommend that the GHG emission accounting/inventory include each proposed stationary source (e.g., power plant, liquefaction facility, compressor and metering stations, etc.) and mobile emission source (e.g., heavy equipment, supply barges, rail transports, etc.). We also recommend that the DEIS establish reasonable spatial and temporal boundaries for this analysis, and that the DEIS quantify and disclose the expected annual direct and indirect GHG emissions for the proposed action. In the analysis of direct effects, we recommend that the DEIS quantify cumulative emissions over the life of the project, discuss measures to reduce GHG emissions, including consideration of reasonable alternatives. EPA recommends that the DEIS consider mitigation measures and reasonable alternatives to reduce action related GHG emissions, and include a discussion of cumulative effects of GHG emissions related to the proposed action.

Recommendation:

EPA recommends that this discussion focus on an assessment of annual and cumulative emissions of the proposed action and the difference in emissions associated with the alternatives. In addition, GHG emission sources in the petroleum and natural gas industry are required to report GHG emissions under 40CFR Part 98 (subpart W), the Greenhouse Gas Reporting Program. Consistent with draft CEQ guidance, we recommend that this information be included in the DEIS for consideration by decision makers and the public. Please see http://www.epa.gov/climatechange/emissions/ghgmlemaking.html.

GHG and NPDES Permitting and Informational Needs

We believe there is a potential that Excelerate's proposed project will require a GHG Prevention of Significant Deterioration (PSD) permit under the Clean Air Act and a National Pollutant Discharge Elimination System (NPDES) permit under the Clean Water Act. The NPDES permitting concern relates to operations and any special construction aspects not associated with stormwater such as needed hydrostatic test discharges for related pipelines and tanks; thermal discharges such as cooling waters impacts to receiving streams and their aquatic communities; and impacts of cooling water intake structures to Essential Fish Habitat (EFH). EPA Region 6 is the permitting authority for these permits in Texas, and we would appreciate the opportunity to meet with FERC staff and the applicant to discuss this permitting issues. If it is ultimately decided that these permits are required, we would like to be a Cooperating Agency with FERC in the preparation of this EIS, and to join with FERC in any consultations regarding compliance with the Endangered Species Act, the National Historic Preservation Act, the Magnuson-Stevens Fishery Conservation and Management Act, and the Coastal Zone Management Act in order to help support our permit decisions.

Hazardous Materials/Hazardous Waste/Solid Waste

The DEIS should address potential direct, indirect and cumulative impacts of hazardous waste from construction and operation of the proposed transmission line and other facilities. The document should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. It should address the applicability of state and federal hazardous waste requirements. Appropriate mitigation should be evaluated, including measures to minimize the generation of hazardous waste (i.e., hazardous waste minimization). Alternate industrial processes using less toxic materials should be evaluated as mitigation since such processes could reduce the volume or toxicity of hazardous materials requiring management and disposal as hazardous waste.

Indirect Impacts

Per CEQ regulations at CFR 1508.8(b), the indirect effects analysis "may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems." The 2012 report from the Energy Information Administrations states that, "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production." That report also notes that about three-quarters of that increased production would be from shale resources. We recommend that FERC consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the Gulf coast, and any potential environmental effects associated with that drilling expansion.

Cumulative and Indirect Impacts

The cumulative impacts analysis should identify how resources, ecosystems, and communities in the vicinity of the project have already been, or will be, affected by past, present, or future activities in the project area. These resources should be characterized in terms of their response to change and capacity to withstand stresses. Trends data should be used to establish a baseline for the affected resources, to evaluate the significance of historical degradation, and to predict the environmental effects of the project components.

For the cumulative impacts assessment, we recommend focusing on resources of concern or resources that are "at risk" and/or are significantly impacted by the proposed project, before mitigation. For this project, the FERC should conduct a thorough assessment of the cumulative impacts, especially in the context of the other developments occurring and proposed in the area, including pending and proposed projects for which EPA may issue permits.

Recommendations:

The DEIS should consider the cumulative impacts associated with other development projects proposed in the area and the potential impacts on various resources including: air quality, water quality, water supply, threatened and endangered species, and terrestrial and aquatic habitats.

Coordination with Tribal Governments

Executive Order 13175, *Consultation and Coordination with Indian Tribal Governments* (November 6, 2000), was issued in order to establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, and to strengthen the United States government-to-government relationships with Indian tribes. If applicable, the DEIS should describe the process and outcome of government-to-government consultation between the FERC and with any and each of the tribal governments within the project area, issues that were raised (if any), and how those issues were addressed in the selection of the proposed alternative.

Recommendation:

The DEIS should describe the process and outcome of government-to-government consultation between the FERC and each of the tribal governments within the project area, issues that were raised (if any), and how those issues were addressed in the selection of the proposed alternative.

National Historic Preservation Act and Executive Order 13007(NRHA)

Consultation for tribal cultural resources is required under Section 106 of the National Historic Preservation Act. Historic properties under the NHPA are properties that are included in the National Register of Historic Places or that meet the criteria for the National Register. Section 106 of the NHPA requires a federal agency, upon determining that activities under its control could affect historic properties, consult with the appropriate State Historic Preservation Officer (SHPO)/Tribal Historic Preservation Officer (THPO), Indian tribes, or any other interested party. Under NEPA, any impacts to tribal, cultural, or other treaty resources must be discussed and mitigated. Section 106 of the NHPA requires that Federal agencies consider the effects of their actions on cultural resources, following regulation in 36 CFR 800.

Recommendation:

The DEIS should address the existence of cultural and historic resources, including Indian sacred sites, in the project areas, and address compliance with Section 106 of the NHPA. It should also address Executive Order 13007, distinguish it from Section 106 of the NHPA, and discuss how the applicant will avoid adversely affecting the physical integrity, accessibility, or use of sacred sites, if they exist. The DEIS should provide a summary of all coordination with Tribes, the SHPO/THPO, or any other party; and identify all NRHP listed or eligible sites, and the development of a Cultural Resource Management Plan.

Environmental Justice and Impacted Communities

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (February 11, 1994) and the Interagency Memorandum of Understanding on Environmental Justice (August 4, 2011) direct federal agencies to identify and address disproportionately high and adverse human health or environmental effects on minority and low-income populations, allowing those populations a meaningful opportunity to participate in the decision-making process. Guidance[5] by CEQ clarifies the terms low-income and minority population (which includes Native Americans) and describes the factors to consider when evaluating disproportionately high and adverse human health effects. The DEIS should include an evaluation of environmental justice populations within the geographic scope of the projects. Assessment of the projects impact on minority and low-income populations should reflect coordination with those affected populations. The DEIS should also describe outreach conducted to all other communities that could be affected by the project, since rural communities may be among the most vulnerable to health risks associated with the project.

Recommendations:

The DEIS should include an evaluation of environmental justice populations within the geographic scope of the projects. If such populations exist, the DEIS should address the

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[5] Environmental Justice Guidance under the National Environmental Policy Act, Appendix A (Guidance for Federal Agencies on Key Terms in Executive Order 12898), CEQ, December 10, 1997.

potential for disproportionate adverse impacts to minority and low-income populations, and the approaches used to foster public participation by these populations. Assessment of the projects impact on minority and low-income populations should reflect coordination with those affected populations.

The DEIS should describe outreach conducted to all other communities that could be affected by the project, since rural communities may be among the most vulnerable to health risks associated with the project.

Coordination with Land Use Planning Activities

The DEIS should discuss how the proposed action would support or conflict with the objectives of federal, state, tribal or local land use plans, policies and controls in the project areas. The term "land use plans" includes all types of formally adopted documents for land use planning, conservation, zoning and related regulatory requirements. Proposed plans not yet developed should also be addressed if they have been formally proposed by the appropriate government body in a written form (CEQ's Forty Questions, #23b).

Eminent domain

Because eminent domain laws vary from state to state, and the proposed pipeline will require many acres for easements and ROW, the DEIS should consider eminent domain issues during the evaluation of potential corridors. The findings should be documented in the DEIS.

Recommendations:
EPA recommends that the DEIS discuss the applicable eminent domain authority for the pipeline ROW.

United States Department of the Interior

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IN REPLY REFER TO
2800 (ORV040)

APR 04 2013

FILED
SECRETARY OF THE
COMMISSION
2013 APR -9 P 2:02
FEDERAL ENERGY
REGULATORY COMMISSION

Dear Interested Public:

This courtesy letter provides a Notice of Internet Availability that the Malheur Resource Area, Vale District BLM, has completed an Environmental Assessment (DOI-BLM-OR-V040-2012-015-EA), Finding of No Significant Impact (FONSI) and Decision Record (DR) identifying the proposed construction to realign approximately 1700 feet of Beulah Road (County Road #510), 900 of which is on BLM administered land, 12 miles north of Juntura, OR. The proposed action will be implemented in accordance with and subject to the guiding land use plan - the Southeastern Oregon Resource Management Plan and Final EIS.

The EA, FONSI, and DR can be viewed on the Vale District website at the following location: http://www.blm.gov/or/districts/vale/plans/index.php.

Persons named in the *Copies sent to:* sections of this notification are considered to be persons "named in the decision from which the appeal is taken." Thus, copies of a notice of appeal and petition for a stay must also be served on these parties, in addition to any party who is named elsewhere in the decision (see 43 CFR 4.413(a) & 43 CFR 4.21(b) (3)) and the appropriate Office of the Solicitor (see 43 CFR 4.413(a), (c)) at the same time the original documents are filed with this office. For privacy reasons, if the decision is posted on the internet, the *Copies sent to:* section will be attached to a notification of internet availability and persons named in that section are also considered to be persons "named in the decision from which the appeal is taken."

If you wish to receive hard copies of these documents, or wish to be removed from the mailing list please call the District Office at 541-473-3144.

Sincerely,

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Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee Second Ninety Day Report

November 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee
Second Ninety Day Report – November 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and to help assure the safety of shale gas production. Shale gas has become an important part of the nation's energy mix. It has grown rapidly from almost nothing at the beginning of the century to near 30 percent of natural gas production. Americans deserve assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. On August 18, 2011 the Subcommittee presented its initial Ninety-Day Report[1] including twenty recommendations that the Subcommittee believes, if implemented, would assure that the nation's considerable shale gas resources are being developed responsibly, in a way that protects human health and the environment and is most beneficial to the nation. The Secretary of Energy's charge to the Subcommittee is included in Annex A and members of the Subcommittee are given in Annex B.

In this report the Subcommittee focuses on implementation of the twenty recommendations presented in its Ninety-day report. The Executive Summary of these recommendations is presented in Annex C.

The Second Ninety-Day Report

The Subcommittee recommendations in its initial report were presented without indicating priority or how each recommendation might be implemented. Progress in achieving the Subcommittee's objective of continuous improvement in reducing the environmental impact of shale gas production depends upon implementation of the Subcommittee recommendation; hence this final report focuses on implementation. On October 31, 2011, the Subcommittee held a public meeting at DOE headquarters in Washington, D.C., to learn the views of the Department of Interior, the Environmental Protection Agency, and the Department of Energy about progress and barriers to implementation of the Subcommittee recommendations.

The Subcommittee is mindful that state and federal regulators and companies are already deeply involved in environmental management. Implementing the twenty Subcommittee recommendations will require a great deal of effort, and regulators, public officials, and companies need to decide how to allocate scarce human and financial resources to each recommendation, potentially shifting effort from other valuable existing activities. All of the Subcommittee recommendations in its Ninety-Day report involve actions by one or more parties: federal officials, state officials, and public and private sector entities.

Two criteria are important in deciding on the allocation: the importance and ease of implementation. Early success in implementing some recommendations may stimulate greater effort on other recommendations, which require greater time and effort for progress. Decisions about when, how and whether to proceed with our recommendations are the responsibility of the public and private participants in the process – not the Subcommittee. But, the Subcommittee can be helpful at identifying those recommendations that seem particularly important and particularly amendable to early action. Accordingly this report classifies the twenty recommendations into three categories:

(1) Recommendations ready for implementation, primarily by federal agencies;
(2) Recommendations ready for implementation, primarily by states;
(3) Recommendations that require new partnerships and mechanisms for success.

The Subcommittee recognizes that successful implementation of each of its recommendations will require cooperation among and leadership by federal, state and local entities. In its initial report, the Subcommittee called for a process of continuous improvement and said: "This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interest groups."

The Subcommittee also believes it has a responsibility to assess and report progress in implementing the recommendations in its initial report. Too often advisory committee recommendations are ignored, not because of disagreement with substance, but because the implementation path is unclear or because of the press of more immediate matters on dedicated individuals who are over extended. The Subcommittee does not wish to see this happen to its recommendation, because it believes citizens expect prompt action. Absent action there will be little credible progress in toward reducing in the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource. At this early stage, it is reasonable to assess if initial, constructive, steps are underway; there is no expectation that any of the recommendations could be completely implemented in the three months since the Subcommittee issued its initial report.

(1) Recommendations for implementation, primarily by federal agencies.

The Subcommittee has identified nine recommendations where federal agencies have primary responsibility and that are ready for implementation; these are presented in Table I.

Recommendation #2 Two existing non-profit organizations – the State Review of Oil and Natural Gas Environmental Regulations (STONGER) and the Ground Water Protection Council (GWPC) are two existing organizations that work to share information to improve the quality of regulatory policy and practice in the states. The budgets for these organizations are small, and merit public support. Previously, federal agencies (DOE and EPA) provided funding for STRONGER and GWPC, but federal funding is currently not provided. To maintain credibility to have an ability to set their own agenda these organizations cannot rely exclusively on funding provided by companies of the regulated industry. The Subcommittee has recommended that $5 million per year would provide the resources to STRONGER and the GWCPC needed to strengthen and broaden its activities as discussed in the Subcommittees previous report, for example, updating hydraulic fracturing guidelines and well construction guidelines, and developing guidelines for water supply, air emissions and cumulative impacts. Additionally, DOE and/or EPA should consider making grants to those states that volunteer to have their regulations and practices peer-reviewed by STRONGER, as an incentive for states to undergo updated reviews and to implement recommended actions.

Table 1. Recommendations ready for immediate implementation

Rec.#	Recommendation	Comment & Status
1.	Improve public information about shale gas operations	Federal responsibility to begin planning for public website. Some discussion between DOE and White House offices about possible hosting sites but no firm plan. States should also consider establishing sites.
2.	Improve communication among federal and state regulators and provide federal funding for STRONGER and the Ground Water Protection Council	Federal funding at $5m/y will allow state regulators/NGOs/industry to plan activities. Possible minor DOE FY2012 funding; no multi-year commitment. See discussion below.
3	Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable.	We encourage EPA to complete its current rule making as it applies to shale gas production quickly, and explicitly include methane, a greenhouse gas, and controls from existing shale gas production sources. Additionally, some states have taken action in this area, and others could do so as well. See discussion below.
4	Enlisting a subset of producers in different basins to design and field a system to collect air emissions data.	Industry initiative in advance of regulation. Several companies have shown interest. Possible start in Marcellus and Eagle Ford. See discussion below.
5	Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of natural gas use.	OSTP has not committed to leading an interagency effort, but the Administration is taking steps to collect additional data, including through the EPA air emissions rulemaking.
6	Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.	A general statement of the importance the Subcommittee places on reducing air emissions. Federal funding at $5m/y for state regulators/NGOs/industry will encourage planning. Some states have taken action in this area, and others could do so as well.
11	Launch addition field studies on possible methane migration from shale gas wells to water reservoirs.	No new studies launched; funding required from fed agencies or from states.[2]
14	Disclosure of Fracturing fluid composition	DOI has announced its intent to propose requirement. Industry appears ready to agree to mandatory stricter disclosure. See discussion below.
15	Elimination of diesel use in fracturing fluids	EPA is developing permitting guidance under the UIC program. The Subcommittee reiterates its recommendation that diesel fuel should be eliminated in hydraulic fracturing fluids.
20	R&D needs	OMB/OSTP must define proper limits for unconventional gas R&D and budget levels for DOE, EPA, and USGS. See discussion below.

Funding for the GWPC would allow the association to extend and expand its *Risk Based Data Management System,* which helps states collected and publicly share data associated with their oil and gas regulatory programs – for example, sampling and monitoring programs for surface waters, water wells, sediments and isotopic activity in and around areas of shale gas operations. Likewise, funding could go toward integrating the RBDMS into the national data portal discussed in Recommendation #1. Funding would also allow GWPC to upgrade its fracturing fluid chemical disclosure registry, *Frac Focus*, so that information can be searched, sorted and aggregated by chemical, by well, by company and by geography – as recommended by the Subcommittee in its 90-Day report.

Recommendation #3 On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.

Additionally, in its Ninety-Day report the Subcommittee recommended that companies be required to measure and disclose air emissions from shale gas sources. Recently, in response to a challenge, the EPA took two final actions that compromise the ability to get accurate emissions data from the oil and gas sector under the Greenhouse Gas Reporting Rule.[3] The Subcommittee reiterates its recommendation that the federal government or state agencies require companies to measure and disclose air emissions from shale gas sources.

Recommendation #4 The Subcommittee is aware that operating companies are considering projects to collect and disclose air emissions data from shale gas production sites. Discussions are underway to define the data to be collected, appropriate instrumentation, and subsequent analysis and disclosure of the data. The Subcommittee welcomes this development and underscores its earlier recommendation for disclosure, including independent technical review of the methodology.

Recommendation #14 The Subcommittee welcomes the announcement of the DOI of its intent to require disclosure of fracturing fluid composition on federal lands. The Subcommittee was pleased to learn from the DOI at its October 31, 2011 public hearing that the agency intends to follow the disclosure recommendations in its Ninety-Day Report that disclosure should include all chemicals, not just those that appear on

Material Safety Data Sheets, and that chemicals should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, by well, by company and by geography. The Subcommittee recognized the need for protection of legitimate trade secrets but believes that the bar for trade secret protection should be high. The Subcommittee believes the DOI disclosure policy should meet the Subcommittee's criteria and that it can serve as a model for the states. The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission have taken an important step in announcing their intent to require disclosure of all chemicals by operators who utilize their voluntary chemical disclosure registry, FracFocus. The Subcommittee welcomes this progress and encourages those organizations to continue their work toward upgrading FracFocus to meet the Subcommittee's recommended disclosure criteria.

Recommendation #20 As set out in its Ninety-day report, the Subcommittee believes there is a legitimate role for the federal government in supporting R&D on shale gas, arguably the country's most important domestic energy resource. To be effective such an R&D program must be pursued for several years, at a relatively modest level. The Subcommittee is aware that discussions have taken place between OMB and the involved agencies, DOI/USGS, DOE, and EPA about funding for unconventional gas R&D. The Subcommittee understands that agreement has been reached that the administration will seek funding for "priority items" for FY2012 in its discussions with Congress, but the "priority items" and the level of this funding is not decided. The Subcommittee welcomes the agencies effort to coordinate their planned out-year research effort for FY2013 and beyond, as described by DOI, DOE, and EPA at its public meeting on October 31, 2011. But, as yet, there has been no agreement with OMB on the scale and composition of a continuing unconventional gas R&D program. Failure to provide adequate funding for R&D would be deleterious and undermine achieving the policy objectives articulated by the President.

Note: after the Subcommittee completed its deliberations the Office of Management and Budget sent a letter setting forth the efforts underway to find funding for the Subcommittee recommendations; **see Annex D**. While the letter does not settle the matter, it is an important and welcome, positive step.

(2) Recommendations ready for implementation, primarily by states.

The Subcommittee has identified four recommendations in this category; all address water quality related issues.

Table 2. Recommendations requiring cooperation between regulators and industry

Rec.#	Recommendation	Comment & Status
8	Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.	Awaits EPA's study underway on the Impacts of hydraulic fracturing on drinking water resources. See discussion below. States should also determine a way forward to measure and record data from flow back operations as many issues will be local issues.
9	Manifest all transfers of water among different locations	
10	Adopt best practices in well development and construction, especially casing, cementing, and pressure management	Widely recognized as a key practice by companies and regulators but no indication of a special initiative on field measurement and reporting.
12	Adopt requirements for background water quality measurements	The value of background measurements is recognized. Jurisdiction for access to private wells differs widely

Recommendation #8 and 9 EPA has a number of regulatory actions in process. On October 20, 2011 EPA announced a schedule setting waste water discharge standards that will affect some shale gas production activities.[4] Further water quality regulatory developments will benefit from the results of EPA's study on the impact of hydraulic fracturing on drinking water that will not be complete until 2014 and will likely initiate significant negotiation between EPA and state regulators on the scope and responsibility for water regulations. The Subcommittee observes that there will be a tremendous amount of activity in the field before EPA completes its study (and any potential regulatory actions that flow from it) and urges the EPA to take action as appropriate during the course of its process.

Recommendation #12 In its initial report, the Subcommittee called for background water measurements at wells surrounding planned production sites to establish an objective benchmark to assess potential damage to water resources. All stakeholders agree that such measurements can be helpful in establishing facts and verifying disputed contamination claims. The lack of a clear pattern of state, local, and federal authority for access to private water wells to make such measurements is an impediment to policy development.

(3) Recommendations that require new partnerships or mechanisms for success

The following recommendations require development of new partnerships or mechanisms and hence the implementation challenge can be quite significant. These recommendations do, however, signal significant concerns shared by members of the Subcommittee that are noted in Table 3. The challenge is to devise new mechanisms for addressing these significant environmental problems.

Table 3. Recommendations that require new mechanisms for success

Rec.#	Recommendation	Comment & Status
7	Protection of water quality through a systems approach.	At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management.
13	Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.	Reflects Subcommittee unease that the present arrangement of shared federal and state responsibility for cradle-to-grave water quality is not working smoothly or as well as it should.
16	Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies.	No new studies launched; funding required from federal agencies or from states. See discussion below.
17	Organizing for best practice.	Industry intends to establish 'centers of excellence' regionally, that involve public interest groups, state and local regulatory and local colleges and universities.
18	Air	
19	Water	

Recommendation #16 Shale gas production brings both benefits and cost of economic development to a community, often rapidly and in a region that it is unfamiliar with oil and gas operations. Short and long term community impact range from traffic, noise, land use, disruption of wildlife and habitat, with little or no allowance for planning or effective mechanisms to bring companies, regulators, and citizens to deliberate about how best to deal with near term and cumulative impacts. The Subcommittee does not believe that these issues will solve themselves or be solved by prescriptive regulation or in the courts. State and local governments should take the lead in experimenting with different mechanisms for engaging these issues in a constructive way, seeking to be beyond discussion to practical mitigation. Successful models should be disseminated.

The U.S. Department of Interior, however, is somewhat unique in having tools at its disposal that could be used to address cumulative and community impacts. For example, Master Leasing and Development Plans, a relatively new tool, might help improve planning for production on federal lands through requirements for phased leasing and development, multi-well pad drilling, limitations on surface disturbance, centralization of infrastructure, land and roadway reclamation, etc.

Recommendation 17, 18 & 19 Industry has always been interested in best practices. The Subcommittee has called for industry to increase their best practices process for field engineering and environmental control activities by adopting the objective of continuous improvement, validated by measurement and disclosure of key operating metrics.[5] Leadership for this initiative lies with industry but also involves regulators and public interest groups. Best practices involves the entire range of shale gas operations including: (a) well design and siting, (b) drilling and well completion, including importantly casing and cementing, (c) hydraulic fracturing, (d) surface operations, (e) collection and distribution of gas and land liquids, (f) well abandonment and sealing, and (g) emergency response. Developing reliable metrics for best practices is a major task and must take into account regional differences of geology and regulatory practice. A properly trained work force is an important element in achieving best practice. Thus, organizing for best practice should include better mechanisms for training of oil field workers. Such training should utilize local community college and vocational education resources.

Industry is taking a regional approach to best practice, building on local organizations, such as the Marcellus Shale Coalition. Shale companies understand the importance of involving non-industry stakeholders in their efforts and are beginning to take initiatives that engage the public in a meaningful way. Industry is showing increased interest in engineering practice as indicated by the recent workshop on hydraulic fracturing sponsored by the American Petroleum Institute on October 4 and 5, 2011 in Pittsburgh PA.[6] The Subcommittee urges leading companies to adopt a more visible commitment to using quantitative measures as a means of achieving best practice and demonstrating to the public that there is continuous improvement in reducing the environmental impact of shale gas production.

Concluding remarks

The Subcommittee was gratified with the generally favorable, but not universally favorable, response to its initial report. In particular there was overwhelming agreement on two points: (1) If the country is to enjoy the economic and other benefits of shale gas production over the coming years disciplined attention must be devoted to reducing the environmental impact that accompanies this development, and (2) a prudent balance between development and environmental protection is best struck by establishing a strong foundation of regulation and enforcement, and adopting a policy and practice that measures, discloses, and continuously improves shale gas operations.

The Subcommittee believes that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity. Thus, the Subcommittee has an interest in assessing and reporting on, the progress that is being made on implementing its recommendations or some sensible variations of these recommendations.

The Subcommittee has the impression that its initial report stimulated interest in taking action to reduce the environmental impact of shale gas production by the administration, state governments, industry, and public interest groups. However, the progress to date is less than the Subcommittee hoped and it is not clear how to catalyze action at a time when everyone’s attention is focused on economic issues, the press of daily business, and an upcoming election. The Subcommittee cautions that whether its approach is followed or not, some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;
- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;

- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore. More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

Annex C – Subcommittee Recommendations

A list of the Subcommittee's findings and recommendations follows.

1. Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

2. Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

3. Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

    4. Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

    5. Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations throughout the lifecycle of natural gas use in comparison to other fuels; and

    6. Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

7. Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

    8. Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

    9. Manifest all transfers of water among different locations.

    10. Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that

hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

11. Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

12. Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

13. Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

14. Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote.[7] Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

15. Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

16. Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

    (1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

    (2) Evaluation of water use at the scale of affected watersheds.

    (3) Formal notification by regulated entities of anticipated environmental and community impacts.

    (4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

    (5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

    (6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

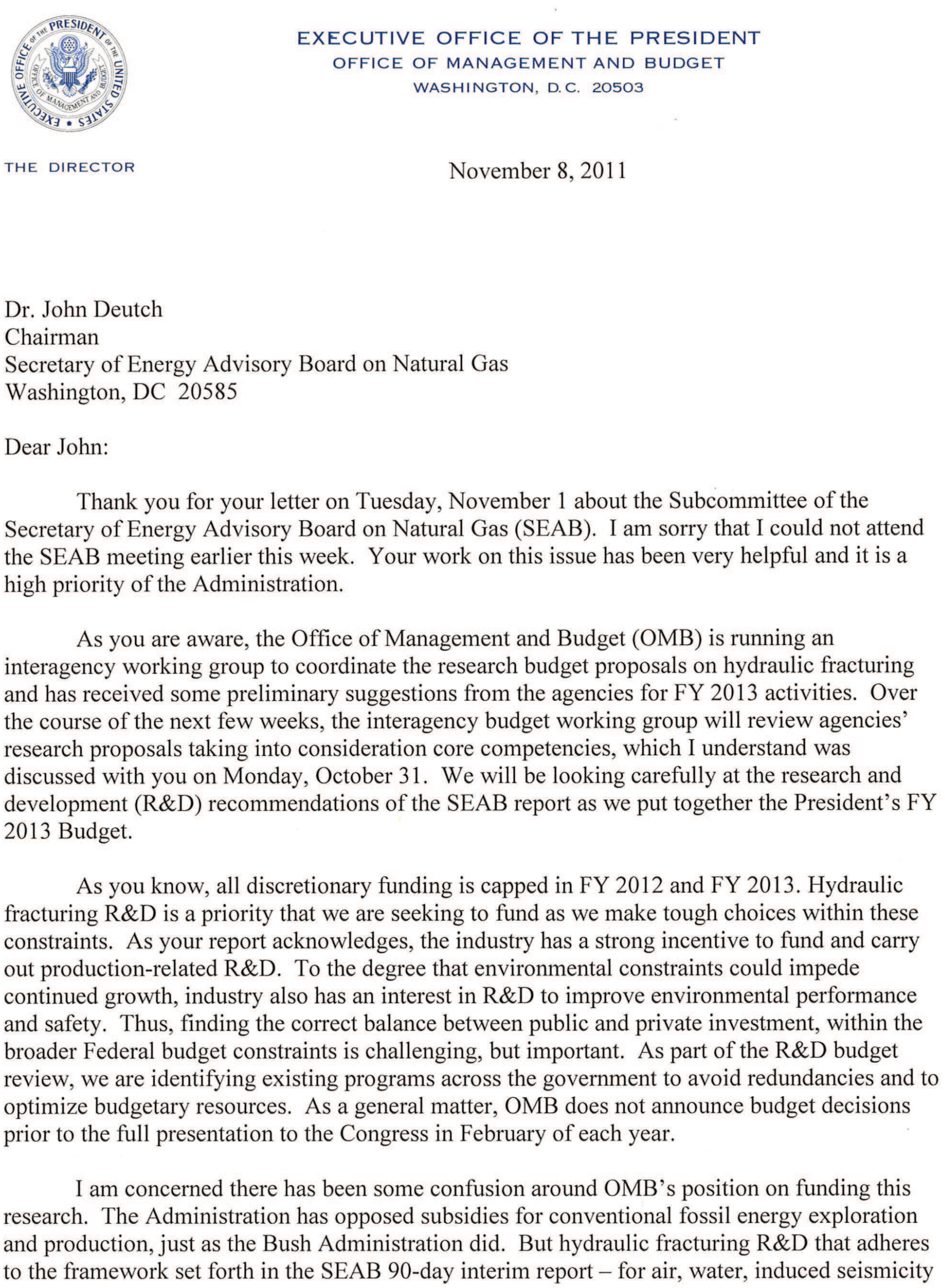
17. Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

    18. Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

    19. Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

20. Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

Annex D Letter from the Office of Management and Budget



EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

THE DIRECTOR

November 8, 2011

Dr. John Deutch
Chairman
Secretary of Energy Advisory Board on Natural Gas
Washington, DC 20585

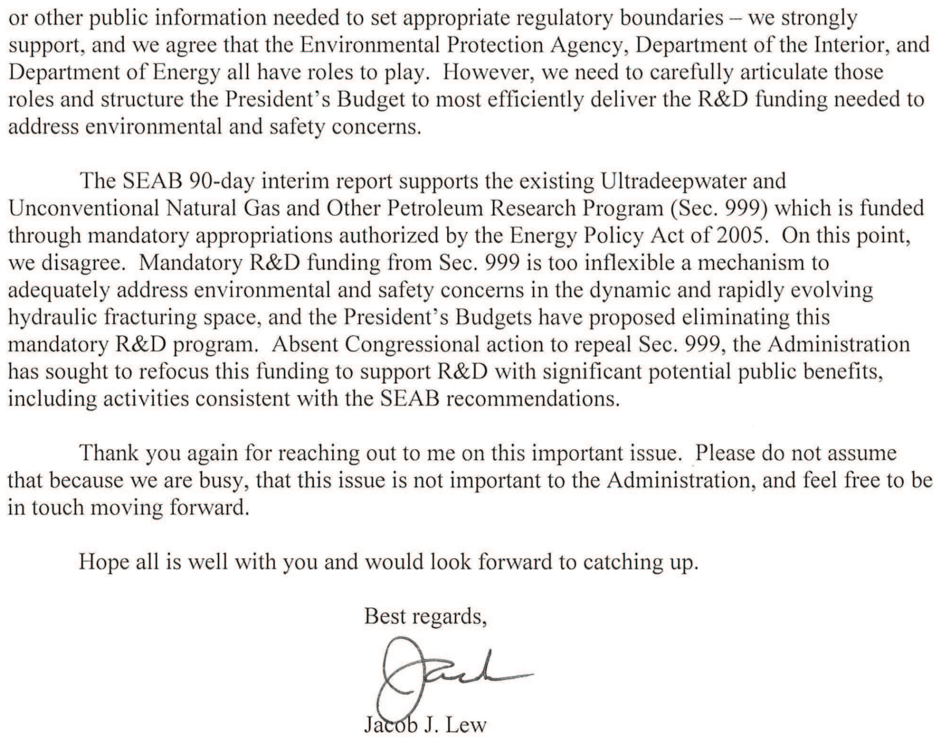
Dear John:

Thank you for your letter on Tuesday, November 1 about the Subcommittee of the Secretary of Energy Advisory Board on Natural Gas (SEAB). I am sorry that I could not attend the SEAB meeting earlier this week. Your work on this issue has been very helpful and it is a high priority of the Administration.

As you are aware, the Office of Management and Budget (OMB) is running an interagency working group to coordinate the research budget proposals on hydraulic fracturing and has received some preliminary suggestions from the agencies for FY 2013 activities. Over the course of the next few weeks, the interagency budget working group will review agencies' research proposals taking into consideration core competencies, which I understand was discussed with you on Monday, October 31. We will be looking carefully at the research and development (R&D) recommendations of the SEAB report as we put together the President's FY 2013 Budget.

As you know, all discretionary funding is capped in FY 2012 and FY 2013. Hydraulic fracturing R&D is a priority that we are seeking to fund as we make tough choices within these constraints. As your report acknowledges, the industry has a strong incentive to fund and carry out production-related R&D. To the degree that environmental constraints could impede continued growth, industry also has an interest in R&D to improve environmental performance and safety. Thus, finding the correct balance between public and private investment, within the broader Federal budget constraints is challenging, but important. As part of the R&D budget review, we are identifying existing programs across the government to avoid redundancies and to optimize budgetary resources. As a general matter, OMB does not announce budget decisions prior to the full presentation to the Congress in February of each year.

I am concerned there has been some confusion around OMB's position on funding this research. The Administration has opposed subsidies for conventional fossil energy exploration and production, just as the Bush Administration did. But hydraulic fracturing R&D that adheres to the framework set forth in the SEAB 90-day interim report – for air, water, induced seismicity



or other public information needed to set appropriate regulatory boundaries – we strongly support, and we agree that the Environmental Protection Agency, Department of the Interior, and Department of Energy all have roles to play. However, we need to carefully articulate those roles and structure the President's Budget to most efficiently deliver the R&D funding needed to address environmental and safety concerns.

The SEAB 90-day interim report supports the existing Ultradeepwater and Unconventional Natural Gas and Other Petroleum Research Program (Sec. 999) which is funded through mandatory appropriations authorized by the Energy Policy Act of 2005. On this point, we disagree. Mandatory R&D funding from Sec. 999 is too inflexible a mechanism to adequately address environmental and safety concerns in the dynamic and rapidly evolving hydraulic fracturing space, and the President's Budgets have proposed eliminating this mandatory R&D program. Absent Congressional action to repeal Sec. 999, the Administration has sought to refocus this funding to support R&D with significant potential public benefits, including activities consistent with the SEAB recommendations.

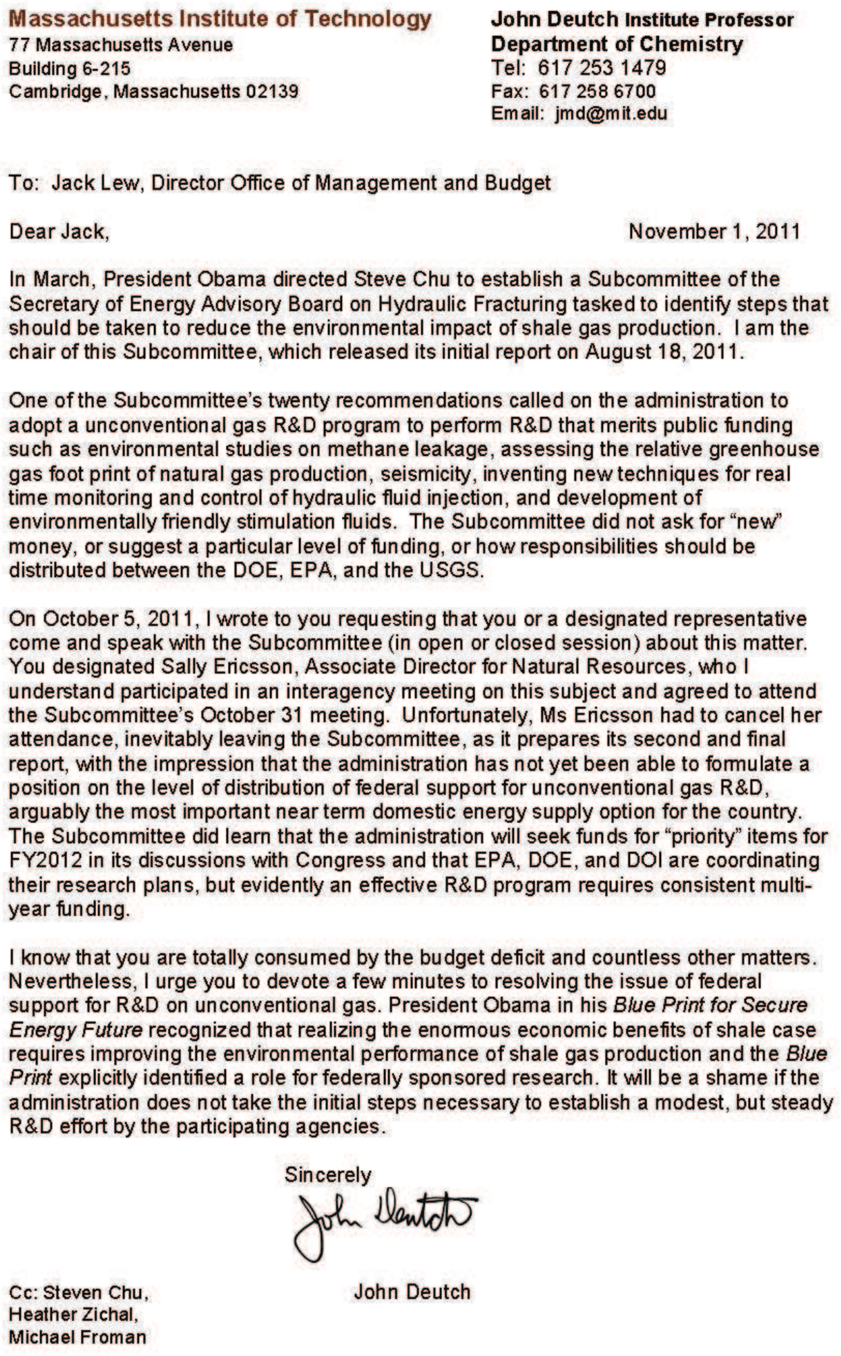
Thank you again for reaching out to me on this important issue. Please do not assume that because we are busy, that this issue is not important to the Administration, and feel free to be in touch moving forward.

Hope all is well with you and would look forward to catching up.

Best regards,

Jack

Jacob J. Lew



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To: Jack Lew, Director Office of Management and Budget

Dear Jack, November 1, 2011

In March, President Obama directed Steve Chu to establish a Subcommittee of the Secretary of Energy Advisory Board on Hydraulic Fracturing tasked to identify steps that should be taken to reduce the environmental impact of shale gas production. I am the chair of this Subcommittee, which released its initial report on August 18, 2011.

One of the Subcommittee's twenty recommendations called on the administration to adopt a unconventional gas R&D program to perform R&D that merits public funding such as environmental studies on methane leakage, assessing the relative greenhouse gas foot print of natural gas production, seismicity, inventing new techniques for real time monitoring and control of hydraulic fluid injection, and development of environmentally friendly stimulation fluids. The Subcommittee did not ask for "new" money, or suggest a particular level of funding, or how responsibilities should be distributed between the DOE, EPA, and the USGS.

On October 5, 2011, I wrote to you requesting that you or a designated representative come and speak with the Subcommittee (in open or closed session) about this matter. You designated Sally Ericsson, Associate Director for Natural Resources, who I understand participated in an interagency meeting on this subject and agreed to attend the Subcommittee's October 31 meeting. Unfortunately, Ms Ericsson had to cancel her attendance, inevitably leaving the Subcommittee, as it prepares its second and final report, with the impression that the administration has not yet been able to formulate a position on the level of distribution of federal support for unconventional gas R&D, arguably the most important near term domestic energy supply option for the country. The Subcommittee did learn that the administration will seek funds for "priority" items for FY2012 in its discussions with Congress and that EPA, DOE, and DOI are coordinating their research plans, but evidently an effective R&D program requires consistent multi-year funding.

I know that you are totally consumed by the budget deficit and countless other matters. Nevertheless, I urge you to devote a few minutes to resolving the issue of federal support for R&D on unconventional gas. President Obama in his *Blue Print for Secure Energy Future* recognized that realizing the enormous economic benefits of shale case requires improving the environmental performance of shale gas production and the *Blue Print* explicitly identified a role for federally sponsored research. It will be a shame if the administration does not take the initial steps necessary to establish a modest, but steady R&D effort by the participating agencies.

Sincerely

John Deutch

John Deutch

Cc: Steven Chu,
Heather Zichal,
Michael Froman

ENDNOTES

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[1] The Subcommittee report is available at: http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf

[2] Duke University has launched a follow-on study effort to its initial methane migration study. NETL, in cooperation with other federal agencies and with PA state agencies, Penn State, and major producers is launching a study limited to two wells. More needs to be done by federal agencies.

[3] First, EPA has finalized a deferral that will prevent the agency from collecting inputs to emissions equations data until 2015 for Subpart W sources. These inputs are critical to verify emissions information calculated using emission equations. Second, EPA has finalized a rule allowing more widespread use of Best Available Monitoring Methods ("BAMM") in 2011 and beyond. This action allows reporters to use more relaxed, non-standard methods when monitoring under Subpart W.
See: Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule, 76 Fed. Reg. 53,057 (Aug. 25, 2011); and Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems: Revisions to Best Available Monitoring Method Provisions, 76 Fed. Reg. 59,533 (Sept. 27, 2011).

[4] The EPA announcement of the schedule to Develop Natural Gas Wastewater Standards can be found on the EPA home web site: http://www.epa.gov/newsroom/. It states:

> **Shale Gas Standards:**Currently, wastewater associated with shale gas extraction is prohibited from being directly discharged to waterways and other waters of the U.S. While some of the wastewater from shale gas extraction is reused or re-injected, a significant amount still requires disposal. As a result, some shale gas wastewater is transported to treatment plants, many of which are not properly equipped to treat this type of wastewater. EPA will consider standards based on demonstrated, economically achievable technologies, for shale gas wastewater that must be met before going to a treatment facility.

[5] Since the release of the Subcommittee's Ninety-Day Report, the National Petroleum Council issued its "Prudent Development" report on September 15, 2011, with its recommendation that:

> "Natural gas and oil companies should establish regionally focused council(s) of excellence in effective environmental, health, and safety practices. These councils should be forums in which companies could identify and disseminate effective environmental, health, and safety practices and technologies that are appropriate to the particular region. These may include operational risk management approaches, better environmental management techniques, and methods for measuring environmental performance. The governance structures, participation processes, and transparency should be designed to: promote engagement of industry and other interested parties; and enhance the credibility of a council's products and the likelihood they can be relied upon by regulators at the state and federal level."

NPC, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," Executive Summary Section II.A.1.

[6] See: http://www.energyfromshale.org/commitment-excellence-hydraulic-fracturing-workshop

[7] An interesting Society of Petroleum Engineers paper sheds light on this point: *Hydraulic Fracture-Height Growth: Real Data,* Kevin Fisher and Norm Warpinski, SPE 145949 available at: http://www.spe.org/atce/2011/pages/schedule/tech_program/documents/spe145949%201.pdf .

Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee 90-Day Report

August 18, 2011

U.S. DEPARTMENT OF
ENERGY

The SEAB Shale Gas Production Subcommittee
Ninety-Day Report – August 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and improve the safety of shale gas production.

Natural gas is a cornerstone of the U.S. economy, providing a quarter of the country's total energy. Owing to breakthroughs in technology, production from shale formations has gone from a negligible amount just a few years ago to being almost 30 percent of total U.S. natural gas production. This has brought lower prices, domestic jobs, and the prospect of enhanced national security due to the potential of substantial production growth. But the growth has also brought questions about whether both current and future production can be done in an environmentally sound fashion that meets the needs of public trust.

This 90-day report presents recommendations that if implemented will reduce the environmental impacts from shale gas production. The Subcommittee stresses the importance of a process of continuous improvement in the various aspects of shale gas production that relies on best practices and is tied to measurement and disclosure. While many companies are following such a process, much-broader and more extensive adoption is warranted. The approach benefits all parties in shale gas production: regulators will have more complete and accurate information; industry will achieve more efficient operations; and the public will see continuous, measurable improvement in shale gas activities.

A list of the Subcommittee's findings and recommendations follows.

- Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

- Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

- Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

  (1) Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

  (2) Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations through out the lifecycle of natural gas use in comparison to other fuels; and

  (3) Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

- Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

  (1) Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

  (2) Manifest all transfers of water among different locations.

  (3) Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators

have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

(4) Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

(5) Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

(6) Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

- Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

- Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

- Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

  (1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

  (2) Evaluation of water use at the scale of affected watersheds.

  (3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

- Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

  Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

  Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

- Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and

> safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

The Subcommittee believes that these recommendations, combined with a continuing focus on and clear commitment to measurable progress in implementation of best practices based on technical innovation and field experience, represent important steps toward meeting public concerns and ensuring that the nation's resources are responsibly being responsibly developed.

Introduction

On March 31, 2011, President Barack Obama declared that "recent innovations have given us the opportunity to tap large reserves – perhaps a century's worth" of shale gas. In order to facilitate this development, ensure environmental protection, and meet public concerns, he instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production.[1] The Secretary's charge to the Subcommittee, included in Annex A, requested that:

> Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracturing.

This is the 90-day report submitted by the Subcommittee to SEAB in fulfillment of its charge. There will be a second report of the Subcommittee after 180 days. Members of the Subcommittee are given in Annex B.

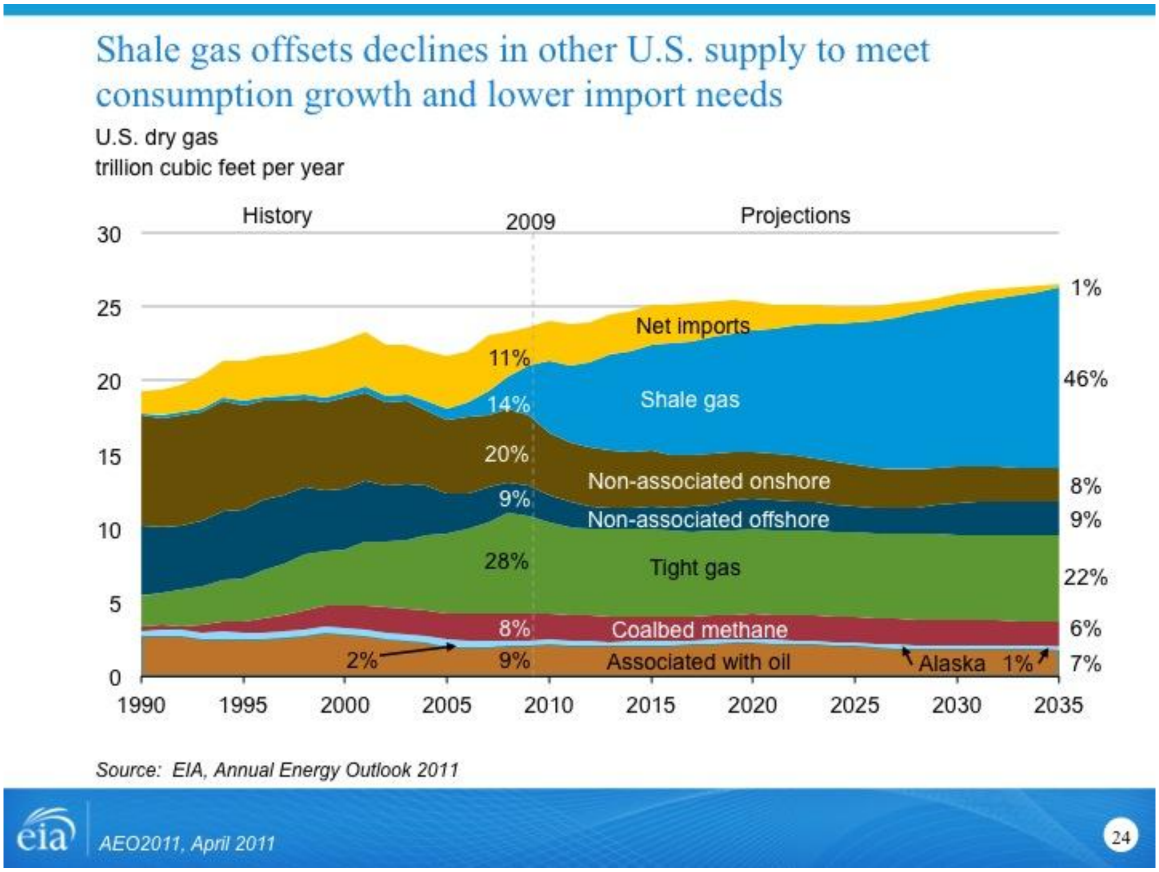
Context for the Subcommittee's deliberations

The Subcommittee believes that the U.S. shale gas resource has enormous potential to provide economic and environmental benefits for the county. Shale gas is a widely distributed resource in North America that can be relatively cheaply produced, creating jobs across the country. Natural gas – if properly produced and transported – also offers climate change advantages because of its low carbon content compared to coal.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Domestic production of shale gas also has the potential over time to reduce dependence on imported oil for the United States. International shale gas production will increase the diversity of supply for other nations. Both these developments offer important national security benefits.[2]

The development of shale gas in the United States has been very rapid. Natural gas from all sources is one of America's major fuels, providing about 25 percent of total U.S. energy. Shale gas, in turn, was less than two percent of total U.S. natural gas production in 2001. Today, it is approaching 30 percent.[3] But it was only around 2008 that the significance of shale gas began to be widely recognized. Since then, output has increased four-fold. It has brought new regions into the supply mix. Output from the Haynesville shale, mostly in Louisiana, for example, was negligible in 2008; today, the Haynesville shale alone produces eight percent of total U.S. natural gas output. According to the U.S. Energy Information Administration (EIA), the rapid expansion of shale gas production is expected to continue in the future. The EIA projects shale gas to be 46 percent of domestic production by 2035. The following figure shows the stunning change.



Shale gas offsets declines in other U.S. supply to meet consumption growth and lower import needs

Source: EIA, Annual Energy Outlook 2011

AEO2011, April 2011

The economic significance is potentially very large. While estimates vary, well over 200,000 of jobs (direct, indirect, and induced) have been created over the last several years by the development of domestic production of shale gas, and tens of thousands more will be created in the future.[4] As late as 2007, before the impact of the shale gas revolution, it was assumed that the United States would be importing large amounts of liquefied natural gas from the Middle East and other areas. Today, the United States is essentially self-sufficient in natural gas, with the only notable imports being from Canada, and expected to remain so for many decades. The price of natural gas has fallen by more than a factor of two since 2008, benefiting consumers in the lower cost of home heating and electricity.

The rapid expansion of production is rooted in change in applications of technology and field practice. It had long been recognized that substantial supplies of natural gas were embedded in shale rock. But it was only in 2002 and 2003 that the combination of two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial.

These factors have brought new regions into the supply mix. Parts of the country, such as regions of the Appalachian mountain states where the Marcellus Shale is located, which have not experienced significant oil and gas development for decades, are now undergoing significant development pressure. Pennsylvania, for example, which produced only one percent of total dry gas production in 2009, is one of the most active new areas of development. Even states with a history of oil and gas development, such as Wyoming and Colorado, have experienced significant development pressures in new areas of the state where unconventional gas is now technically and economically accessible due to changes in drilling and development technologies.

The urgency of addressing environmental consequences

As with all energy use, shale gas must be produced in a manner that prevents, minimizes and mitigates environmental damage and the risk of accidents and protects public health and safety. Public concern and debate about the production of shale gas has grown as shale gas output has expanded.

The Subcommittee identifies four major areas of concern: (1) Possible pollution of drinking water from methane and chemicals used in fracturing fluids; (2) Air pollution; (3) Community disruption during shale gas production; and (4) Cumulative adverse impacts that intensive shale production can have on communities and ecosystems.

There are serious environmental impacts underlying these concerns and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible. Absent effective control, public opposition will grow, thus putting continued production at risk. Moreover, with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced a more serious problem. Effective action requires both strong regulation and a shale gas industry in which all participating companies are committed to continuous improvement.

The rapid expansion of production and rapid change in technology and field practice, requires federal and state agencies to adapt and evolve their regulations. Industry's pursuit of more efficient operations often has environmental as well as economic benefits, including waste minimization, greater gas recovery, less water usage, and a reduced operating footprint. So there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators.

Subcommittee scope, procedure and outline of this report

Scope: The Subcommittee has focused exclusively on production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee is aware that some of the observations and recommendations in this report could lead to extension of its findings to other oil and gas operations, but our intention is to focus singularly on issues related to shale gas development. We caution against applying our findings to other areas, because the Subcommittee has not considered the different development practices and other types of geology, technology, regulation and industry practice.

These shale plays in different basins have different geological characteristics and occur in areas with very different water resources. In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume. This geological diversity means that engineering practice and regulatory oversight will differ widely among regions of the country.

The Subcommittee describes in this report a comprehensive and collaborative approach to managing risk in shale gas production.   The Subcommittee believes that a more systematic commitment to a process of *continuous improvement* to identify and implement best practices is needed, and should be embraced by all companies in the shale gas industry. Many companies already demonstrate their commitment to the kind of process we describe here, but the public should be confident that this is the practice across the industry.

This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interests groups. The process should identify best practices that evolve as operational experience increases, knowledge of environmental effects and effective mitigation grows, and know-how and technology changes. It should also be supported by technology peer reviews that report on individual companies' performance and should be seen as a compliment to, not a substitute for, strong regulation and effective enforcement. There will be three benefits:

- For industry: As all firms move to adopt identified best practices, continuous improvement has the potential to both enhance production efficiency and reduce environmental impacts over time.
- For regulators: Sharing data and best practices will better inform regulators and help them craft policies and regulations that will lead to sounder and more efficient environmental practices than are now in place.
- For the public: Continuous improvement coupled with rigorous regulatory oversight can provide confidence that processes are in place that will result in improved safety and less environmental and community impact.

The realities of regional diversity of shale gas resources and rapid change in production practices and technology mean that a single best engineering practice cannot set for all locations and for all time. Rather, the appropriate starting point is to understand what are regarded as "best practices" today, how the current regulatory system works in the context of those operating in different parts of the country, and establishing a culture of continuous improvement.

The Subcommittee has considered the safety and environmental impact of all steps in shale gas production, not just hydraulic fracturing.[5] Shale gas production consists of several steps, from well design and surface preparation, to drilling and cementing steel casing at multiple stages of well construction, to well completion. The various steps include perforation, water and fracturing fluid preparation, multistage hydraulic fracturing, collection and handling of flow-back and produced water, gas collection, processing and pipeline transmission, and site remediation.[6] Each of these activities has safety and environmental risks that are addressed by operators and by regulators in different ways according to location. In light of these processes, the Subcommittee interprets its charge to assess this entire system, rather than just hydraulic fracturing.

The Subcommittee's charge is not to assess the balance of the benefits of shale gas use against these environmental costs. Rather, the Subcommittee's charge is to identify steps that can be taken to reduce the environmental and safety risks associated with shale gas development and, importantly, give the public concrete reason to believe that environmental impacts will be reduced and well managed on an ongoing basis, and that problems will be mitigated and rapidly corrected, if and when they occur.

It is not within the scope of the Subcommittee's 90-day report to make recommendations about the proper regulatory roles for state and federal governments. However, the Subcommittee emphasizes that effective and capable regulation is essential to protect the public interest. The challenges of protecting human health and the environment in light of the anticipated rapid expansion of shale gas production require the joint efforts of state and federal regulators. This means that resources dedicated to oversight of the industry must be sufficient to do the job and that there is adequate regulatory staff at the state and federal level with the technical expertise to issue, inspect, and enforce regulations. Fees, royalty payments and severance taxes are appropriate sources of funds to finance these needed regulatory activities.

The nation has important work to do in strengthening the design of a regulatory system that sets the policy and technical foundation to provide for continuous improvement in the protection of human health and the environment. While many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear. Raw statistics about enforcement actions and compliance are not sufficient to draw conclusions about regulatory effectiveness. Informed conclusions about the state of shale gas operations require analysis of the vast amount of data that is publically available, but there are surprisingly few published studies of this publically available data. Benchmarking is needed for the efficacy of existing regulations and consideration of additional mechanisms for assuring compliance such as disclosure of company performance and enforcement history, and operator certification of performance subject to stringent fines, if violated.

Subcommittee Procedure: In the ninety days since its first meeting, the Subcommittee met with representatives of industry, the environmental community, state regulators, officials of the Environmental Protection Agency, the Department of Energy, the Department of the Interior, both the United States Geologic Survey (USGS) and the Bureau of Land Management (BLM), which has responsibility for public land regulation,[7] and a number of individuals from industry and not-for-profit groups with relevant expertise and interest. The Subcommittee held a public meeting attended by over four hundred citizens in Washington Country, PA, and visited several Marcellus shale gas sites. The Subcommittee strove to hold all of its meeting in public although the Subcommittee held several private working sessions to review what it had learned and to deliberate on its course of action. A website is available that contains the Subcommittee meeting agendas, material presented to the Subcommittee, and numerous public comments.[8]

Outline of this report: The Subcommittee findings and recommendations are organized in four sections:

- Making information about shale gas production operations more accessible to the public – an immediate action.
- Immediate and longer term actions to reduce environmental and safety risks of shale gas operations
- Creation of a Shale Gas Industry Operation organization, on national and/or regional basis, committed to continuous improvement of best operating practices.
- R&D needs to improve safety and environmental performance – immediate and long term opportunities for government and industry.

The common thread in all these recommendations is that measurement and disclosure are fundamental elements of good practice and policy for all parties. Data enables companies to identify changes that improve efficiency and environmental performance and to benchmark against the performance of different companies. Disclosure of data permits regulators to identify cost/effective regulatory measures that better protect the environment and public safety, and disclosure gives the public a way to measure progress on reducing risks.

Making shale gas information available to the public

The Subcommittee has been struck by the enormous difference in perception about the consequences of shale gas activities. Advocates state that fracturing has been performed safety without significant incident for over 60 years, although modern shale gas fracturing of two mile long laterals has only been done for something less than a decade. Opponents point to failures and accidents and other environmental impacts, but these incidents are typically unrelated to hydraulic fracturing *per se* and sometimes lack supporting data about the relationship of shale gas development to incidence and consequences.[9] An industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed.

Some of this difference in perception can be attributed to communication issues. Many in the concerned public use the word “fracking” to describe all activities associated with shale gas development, rather than just the hydraulic fracturing process itself. Public concerns extend to accidents and failures associated with poor well construction and operation, surface spills, leaks at pits and impoundments, truck traffic, and the cumulative impacts of air pollution, land disturbance and community disruption.

The Subcommittee believes there is great merit to creating a national database to link as many sources of public information as possible with respect to shale gas development and production. Much information has been generated over the past ten years by state and federal regulatory agencies. Providing ways to link various databases and, where possible, assemble data in a comparable format, which are now in perhaps a hundred different locations, would permit easier access to data sets by interested parties.

Members of the public would be able to assess the current state of environmental protection and safety and inform the public of these trends. Regulatory bodies would be better able to assess and monitor the trends in enforcement activities. Industry would be able to analyze data on production trends and comparative performance in order to identify effective practices.

<u>The Subcommittee recommends creation of this national database</u>. A rough estimate for the initial cost is $20 million to structure and construct the linkages necessary for assembling this virtual database, and about $5 million annual cost to maintain it. This recommendation is not aimed at establishing new reporting requirements. Rather, it focuses on creating linkages among information and data that is currently collected and technically and legally capable of being made available to the public. What analysis of the data should be done is left entirely for users to decide.[10]

<u>There are other important mechanisms for improving the availability and usefulness of shale gas information among various constituencies</u>. The Subcommittee believes two such mechanisms to be exceptionally meritorious (and would be relatively inexpensive to expand).

The first is an existing organization known as STRONGER – the State Review of Oil and Natural Gas Environmental Regulation. STRONGER is a not-for-profit organization whose purpose is to accomplish genuine peer review of state regulatory activities. The peer reviews (conducted by a panel of state regulators, industry representatives, and environmental organization representatives with respect to the processes and policies of the state under review) are published publicly, and provide a means to share information about environmental protection strategies, techniques, regulations, and measures for program improvement. Too few states participate in STRONGER's voluntary review of state regulatory programs. The reviews allow for learning to be shared by states and the expansion of the STRONGER process should be encouraged. The Department of Energy, the Environmental Protection Agency, and the American Petroleum Institute have supported STRONGER over time.[11]

The second is the Ground Water Protection Council's project to extend and expand the *Risk Based Data Management System, which* allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.[12]

The Subcommittee recommends that these two activities be funded at the level of $5 million per year beginning in FY2012. Encouraging these multi-stakeholder mechanisms will help provide greater information to the public, enhancing regulation and improving the efficiency of shale gas production. It will also provide support for STRONGER to expand its activities into other areas such as air quality, something that the Subcommittee encourages the states to do as part of the scope of STRONGER peer reviews.

Recommendations for immediate and longer term actions to reduce environmental and safety risks of shale gas operations

1. Improvement in air quality by reducing emissions of regulated pollutants and methane.

Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.

As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[13]

The Environmental Protection Agency has the responsibility to regulate air emissions and in many cases delegate its authority to states. On July 28, 2011, EPA proposed amendments to its regulations for air emissions for oil and gas operations. If finalized and fully implemented, its proposal will reduce emissions of VOCs, air toxics and, collaterally, methane. EPA's proposal does not address many existing types of sources in the natural gas production sector, with the notable exception of hydraulically fractured well re-completions, at which "green" completions must be used. ("Green" completions use equipment that will capture methane and other air contaminants, avoiding its release.) EPA is under court order to take final action on these clean air measures in 2012. In addition, a number of states – notably, Wyoming and Colorado – have taken proactive steps to address air emissions from oil and gas activities.

The Subcommittee supports adoption of emission standards for both new and existing sources for methane, air toxics, ozone-forming pollutants, and other major airborne contaminants resulting from natural gas exploration, production, transportation and distribution activities. The Subcommittee also believes that companies should be required, as soon as practicable, to measure and disclose air pollution emissions, including greenhouse gases, air toxics, ozone precursors and other pollutants. Such disclosure should include direct measurements wherever feasible; include characterization of chemical composition of the natural gas measured; and be reported on a publically accessible website that allows for searching and aggregating by pollutant, company, production activity and geography.

Methane emissions from shale gas drilling, production, gas processing, transmission and storage are of particular concern because methane is a potent greenhouse gas: 25 to 72 times greater warming potential than carbon dioxide on 100-year and 20-year time scales respectively.[14] Currently, there is great uncertainty about the scale of methane emissions.

The Subcommittee recommends three actions to address the air emissions issue.

First, inadequate data are available about how much methane and other air pollutants are emitted by the consolidated production activities of a shale gas operator in a given area, with such activities encompassing drilling, fracturing, production, gathering, processing of gas and liquids, flaring, storage, and dispatch into the pipeline transmission and distribution network. Industry reporting of greenhouse gas emissions in 2012 pursuant to EPA's reporting rule will provide new insights, but will not eliminate key uncertainties about the actual amount and variability in emissions.

The Subcommittee recommends enlisting a subset of producers in different basins, on a voluntary basis, to immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data.

These pioneering data sets will be useful to regulators and industry in setting benchmarks for air emissions from this category of oil and gas production, identifying cost-effective procedures and equipment changes that will reduce emissions; and guiding practical regulation and potentially avoid burdensome and contentious regulatory procedures. Each project should be conducted in a transparent manner and the results should be publicly disclosed.

There needs to be common definitions of the emissions and other parameters that should be measured and measurement techniques, so that comparison is possible between the data collected from the various projects. Provision should be made for an independent technical review of the methodology and results to establish their credibility. The Subcommittee will report progress on this proposal during its next phase.

<u>The second recommendation regarding air emissions concerns the need for a thorough assessment of the greenhouse gas footprint for cradle-to-grave use of natural gas</u>. This effort is important in light of the expectation that natural gas use will expand and substitute for other fuels. There have been relatively few analyses done of the question of the greenhouse gas footprint over the entire fuel-cycle of natural gas production, delivery and use, and little data are available that bear on the question. A recent peer-reviewed article reaches a pessimistic conclusion about the greenhouse gas footprint of shale gas production and use – a conclusion not widely accepted.[15] DOE's National Energy Technology Laboratory has given an alternative analysis.[16] Work has also been done for electric power, where natural gas is anticipated increasingly to substitute for coal generation, reaching a more favorable conclusion that natural gas results in about one-half the equivalent carbon dioxide emissions.[17]

The Subcommittee believes that additional work is needed to establish the extent of the footprint of the natural gas fuel cycle in comparison to other fuels used for electric power and transportation because it is an important factor that will be considered when formulating policies and regulations affecting shale gas development. These data will help answer key policy questions such as the time scale on which natural gas fuel switching strategies would produce real climate benefits through the full fuel cycle and the level of methane emission reductions that may be necessary to ensure such climate benefits are meaningful.

The greenhouse footprint of the natural gas fuel cycle can be either estimated indirectly by using surrogate measures or preferably by collecting actual data where it is practicable to do so. In the selection of methods to determine actual emissions, preference should be given to direct measurement wherever feasible, augmented by emissions factors that have been empirically validated. Designing and executing a comprehensive greenhouse gas footprint study based on actual data – the Subcommittee's recommended approach -- is a major project. It requires agreement on measurement equipment, measurement protocols, tools for integrating and analyzing data from different regions, over a multiyear period. Since producer, transmission and distribution pipelines, end-use storage and natural gas many different companies will necessarily be involved. A project of this scale will be expensive. Much of the cost will be borne by firms in the natural gas enterprise that are or will be required to collect and report air emissions. These measurements should be made as rapidly as practicable. Aggregating, assuring quality control and analyzing these data is a substantial task involving significant costs that should be underwritten by the federal government.

It is not clear which government agency would be best equipped to manage such a project. The Subcommittee recommends that planning for this project should begin immediately and that the Office of Science and Technology Policy, should be asked to coordinate an interagency effort to identify sources of funding and lead agency responsibility. This is a pressing question so a clear blueprint and project timetable should be produced within a year.

Third, the Subcommittee recommends that industry and regulators immediately expand efforts to reduce air emissions using proven technologies and practices. Both methane and ozone precursors are of concern. Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

Ozone precursors should be reduced by using cleaner engine fuel, deploying vapor recovery and other control technologies effective on relevant equipment." Wyoming's emissions rules represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

2. Protecting water supply and water quality.

The public understandably wants implementation of standards to ensure shale gas production does not risk polluting drinking water or lakes and streams. The challenge to proper understanding and regulation of the water impacts of shale production is the great diversity of water use in different regional shale gas plays and the different pattern of state and federal regulation of water resources across the country. The U.S. EPA has certain authorities to regulate water resources and it is currently undertaking a two-year study under congressional direction to investigate the potential impacts of hydraulic fracturing on drinking water resources.[18]

Water use in shale gas production passes through the following stages: (1) water acquisition, (2) drilling and hydraulic fracturing (surface formulation of water, fracturing chemicals and sand followed by injection into the shale producing formation at various locations), (3) collection of return water, (4) water storage and processing, and (5) water treatment and disposal.

The Subcommittee offers the following observations with regard to these water issues:

(1) Hydraulic fracturing stimulation of a shale gas well requires between 1 and 5 million gallons of water. While water availability varies across the country, in most regions water used in hydraulic fracturing represents a small fraction of total water consumption. Nonetheless, in some regions and localities there are significant concerns about consumptive water use for shale gas development.[19] There is considerable debate about the water intensity of natural gas compared to other fuels for particular applications such as electric power production.[20]

One of the commonly perceived risks from hydraulic fracturing is the possibility of leakage of fracturing fluid through fractures into drinking water. Regulators and geophysical experts agree that the likelihood of properly injected fracturing fluid reaching drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. In the great majority of regions where shale gas is being produced, such separation exists and there are few, if any, documented examples of such migration. An improperly executed fracturing fluid injection can, of course, lead to surface spills and leakage into surrounding shallow drinking water formations. Similarly, a well with poorly cemented casing could potentially leak, regardless of whether the well has been hydraulically fractured.

With respect to stopping surface spills and leakage of contaminated water, the Subcommittee observes that extra measures are now being taken by some operators and regulators to address the public's concern that water be protected. The use of mats, catchments and groundwater monitors as well as the establishment of buffers around surface water resources help ensure against water pollution and should be adopted.

Methane leakage from producing wells into surrounding drinking water wells, exploratory wells, production wells, abandoned wells, underground mines, and natural migration is a greater source of concern. The presence of methane in wells surrounding a shale gas production site is not *ipso facto* evidence of methane leakage from the fractured producing well since methane may be present in surrounding shallow methane deposits or the result of past conventional drilling activity.

However, a recent, credible, peer-reviewed study documented the higher concentration of methane originating in shale gas deposits (through isotopic abundance of C-13 and the presence of trace amounts of higher hydrocarbons) into wells surrounding a producing shale production site in northern Pennsylvania.[21] The Subcommittee recommends several studies be commissioned to confirm the validity of this study and the extent of methane migration that may take place in this and other regions.

(2) Industry experts believe that methane migration from shale gas production, when it occurs, is due to one or another factors: drilling a well in a geological unstable location; loss of well integrity as a result of poor well completion (cementing or casing) or poor production pressure management. Best practice can reduce the risk of this failure mechanism (as discussed in the following section).
Pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of

formation isolation. Similarly, frequent microseismic surveys should be carried out to assure operators and service companies that hydraulic fracture growth is limited to the gas-producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing (squeeze jobs).

(3) A producing shale gas well yields flow-back and other produced water. The flow-back water is returned fracturing water that occurs in the early life of the well (up to a few months) and includes residual fracturing fluid as well as some solid material from the formation. Produced water is the water displaced from the formation and therefore contains substances that are found in the formation, and may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds. Both the amount and the composition of the flow-back and produced water vary substantially among shale gas plays – for example, in the Eagle Ford area, there is very little returned water after hydraulic fracturing whereas, in the Marcellus, 20 to 40 percent of the fracturing fluid is produced as flow-back water. In the Barnett, there can significant amounts of saline water produced with shale gas if hydraulic fractures propagate downward into the Ellenburger formation.

(4) The return water (flow-back + produced) is collected (frequently from more than a single well), processed to remove commercially viable gas and stored in tanks or an impoundment pond (lined or unlined). For pond storage evaporation will change the composition. Full evaporation would ultimately leave precipitated solids that must be disposed in a landfill. Measurement of the composition of the stored return water should be a routine industry practice.

(5) There are four possibilities for disposal of return water: reuse as fracturing fluid in a new well (several companies, operating in the Marcellus are recycling over 90 percent of the return water); underground injection into disposal wells (this mode of disposal is regulated by the EPA); waste water treatment to produce clean water (though at present, most waste water treatment plants are not equipped with the capability to treat many of the contaminants associated with shale gas waste water); and surface runoff which is forbidden.

Currently, the approach to water management by regulators and industry is not on a “systems basis” where all aspect of activities involving water use is planned, analyzed, and managed on an integrated basis. The difference in water use and regulation in different shale plays means that there will not be a single water management integrated system applicable in all locations. Nevertheless, the Subcommittee believes certain common principles should guide the development of integrated water management and identifies three that are especially important:

- Adoption of a life cycle approach to water management from the beginning of the production process (acquisition) to the end (disposal): all water flows should be tracked and reported quantitatively throughout the process.
- Measurement and public reporting of the composition of water stocks and flow throughout the process (for example, flow-back and produced water, in water ponds and collection tanks).
- Manifesting of all transfers of water among locations.

Early case studies of integrated water management are desirable so as to provide better bases for understanding water use and disposition and opportunities for reduction of risks related to water use. The Subcommittee supports EPA’s retrospective and prospective case studies that will be part of the EPA study of hydraulic fracturing impacts on drinking water resources, but these case studies focus on identification of possible consequences rather than the definition of an integrated water management system, including the measurement needs to support it. The Subcommittee believes that development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Additionally, agencies should review field experience and modernize rules and enforcement practices – especially regarding well construction/operation, management of flow back and produced water, and prevention of blowouts and surface spills – to ensure robust protection of drinking and surface waters. Specific best practice matters that should receive priority attention from regulators and industry are described below.

3. Background water quality measurements.

At present there are widely different practices for measuring the water quality of wells in the vicinity of a shale gas production site. Availability of measurements in advance of drilling would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.

The Subcommittee is aware there is great variation among states with respect to their statutory authority to require measurement of water quality of private wells, and that the process of adopting practical regulations that would be broadly acceptable to the public would be difficult. Nevertheless, the value of these measurements for reassuring communities about the impact of drilling on their community water supplies leads the Subcommittee to recommend that states and localities adopt systems for measurement and reporting of background water quality in advance of shale gas production activity. These baseline measurements should be publicly disclosed, while protecting landowner’s privacy.

4. Disclosure of the composition of fracturing fluids.

There has been considerable debate about requirements for reporting all chemicals (both composition and concentrations) used in fracturing fluids. Fracturing fluid refers to the slurry prepared from water, sand, and some added chemicals for high pressure injection into a formation in order to create fractures that open a pathway for release of the oil and gases in the shale. Some states (such as Wyoming, Arkansas and Texas) have adopted disclosure regulations for the chemicals that are added to fracturing fluid, and the U.S. Department of Interior has recently indicated an interest in requiring disclosure for fracturing fluids used on federal lands.

The DOE has supported the establishment and maintenance of a relatively new website, FracFocus.org (operated jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission) to serve as a voluntary chemical registry for individual companies to report all chemicals that would appear on Material Safety Data Sheets (MSDS) subject to certain provisions to protect “trade secrets.” While FracFocus is off to a good start with voluntary reporting growing rapidly, the restriction to MSDS data means that a large universe of chemicals frequently used in hydraulic fracturing treatments goes unreported. MSDS only report chemicals that have been deemed to be hazardous in an occupational setting under standards adopted by OSHA (the Occupational Safety and Health Administration); MSDA reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways. Another limitation of FracFocus is that the information is not maintained as a database. As a result, the ability to search for data is limited and there are no tools for aggregating data.

The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The Subcommittee believes that public confidence in the safety of fracturing would be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high. Therefore the Subcommittee recommends that regulatory entities immediately develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands. Disclosure should include all chemicals, not just those that appear on MSDS. It should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography.

5. Reducing the use of diesel in shale gas development

Replacing diesel with natural gas or electric power for oil field equipment will decrease harmful air emissions and improve air quality. Although fuel substitution will likely happen over time because of the lower cost of natural gas compared diesel and because of likely future emission restrictions, the Subcommittee recommends conversion from diesel to natural gas for equipment fuel or to electric power where available, as soon as practicable. The process of conversion may be slowed because manufacturers of compression ignition or spark ignition engines may not have certified the engine operating with natural gas fuel for off-road use as required by EPA air emission regulations.[22]

Eliminating the use of diesel as an additive to hydraulic fracturing fluid**.** The Subcommittee believes there is no technical or economic reason to use diesel as a stimulating fluid. Diesel is a refinery product that consists of several components possibly including some toxic impurities such as benzene and other aromatics. (EPA is currently considering permitting restrictions of the use of diesel fuels in hydraulic fracturing under Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II.) Diesel is convenient to use in the oil field because it is present for use fuel for generators and compressors.

Diesel has two uses in hydraulic fracturing and stimulation. In modest quantities diesel is used to solubilize other fracturing chemical such as guar. Mineral oil (a synthetic mixture of C-10 to C-40 hydrocarbons) is as effective at comparable cost. Infrequently, diesel is use as a fracturing fluid in water sensitive clay and shale reservoirs. In these cases, light crude oil that is free of aromatic impurities picked up in the refining process, can be used as a substitute of equal effectiveness and lower cost compared to diesel, as a non-aqueous fracturing fluid.

6. Managing short-term and cumulative impacts on communities, land use, wildlife and ecologies.

Intensive shale gas development can potentially have serious impacts on public health, the environment and quality of life – even when individual operators conduct their activities in ways that meet and exceed regulatory requirements. The combination of impacts from multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.

The Subcommittee believes that federal, regional, state and local jurisdictions need to place greater effort on examining these cumulative impacts in a more holistic manner; discrete permitting activity that focuses narrowly on individual activities does not reach to these issues. Rather than suggesting a simple prescription that every jurisdiction should follow to assure adequate consideration of these impacts, the Subcommittee believes that each relevant jurisdiction should develop and implement processes for community engagement and for preventing, mitigating and remediating surface impacts and community impacts from production activities. There are a number of threshold mechanisms that should be considered:

- Optimize use of multi-well drilling pads to minimize transport traffic and needs for new road construction.
- Evaluate water use at the scale of affected watersheds.
- Provide formal notification by regulated entities of anticipated environmental and community impacts.
- Declare unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.
- Undertake science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.
- Establish effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.
- Mitigate noise, air and visual pollution.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of mineral rights owners.

Organizing for continuous improvement of “best practice”

In this report, the term “Best Practice” refers to industry techniques or methods that have proven over time to accomplish given tasks and objectives in a manner that most acceptably balances desired outcomes and avoids undesirable consequences. Continuous best practice in an industry refers to the evolution of best practice by adopting process improvements as they are identified, thus progressively improving the level and narrowing the distribution of performance of firms in the industry. Best practice is a particularly helpful management approach in a field that is growing rapidly, where technology is changing rapidly, and involves many firms of different size and technical capacity.

Best practice does not necessarily imply a single process or procedure; it allows for a range of practice that is believed to be equally effective at achieving desired out comes. This flexibility is important because it acknowledges the possibility that different operators in different regions will select different solutions.

The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice through development of standards, diffusion of these standards, and assessing compliance among its members can be an important mechanism for improving shale gas companies' commitment to safety and environmental protection as it carries out its business. The Subcommittee envisions that the industry organization would be governed by a board of directors composed of member companies, on a rotating basis, along with external members, for example from non-governmental organizations and academic institutions, as determined by the board.

Strong regulations and robust enforcement resources and practices are a prerequisite to protecting health, safety and the environment, but the job is easier where companies are motivated and committed to adopting best engineering and environmental practice. Companies have economic incentives to adopt best practice, because it improves operational efficiency and, if done properly, improves safety and environmental protection.

Achievement of best practice requires management commitment, adoption and dissemination of standards that are widely disseminated and periodically updated on the basis of field experience and measurements. A trained work force, motivated to adopt best practice, is also necessary. Creation of an industry organization dedicated to excellence in shale gas operations intended to advance knowledge about best practice and improve the interactions among companies, regulators and the public would be a major step forward.

The Subcommittee is aware that shale gas producers and other groups recognize the value of a best practice management approach and that industry is considering creating a mechanism for encouraging best practice. The design of such a mechanism involves many considerations including the differences in the shale production and regulations in different basins, making most effective use of mechanisms that are currently in place, and respecting the different capabilities of large and smaller operators. The Subcommittee will monitor progress on this important matter and continue to make its views known about the characteristics that such a mechanism and supporting organization should possess to maximize its effectiveness.

It should be stressed that any industry best practice mechanism would need to comply with anti-trust laws and would not replace any existing state or federal regulatory authority.

Priority best practice topics

Air
- Measurement and disclosure of air emissions including VOCs, methane, air toxics, and other pollutants.
- Reduction of methane emission from all shale gas operations

Water
- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

The Subcommittee has identified a number of promising best practice opportunities. Five examples are given in the call-out box. Two examples are discussed below to give a sense of the opportunities that presented by best practice focus.

Well integrity: an example. Well integrity is an example of the potential power of best practice for shale gas production. Well integrity encompasses the planning, design and execution of a well completion (cementing, casing and well head placement). It is fundamental to good outcomes in drilling oil and gas wells.

Methane leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing. Casing and cementing programs should be designed to provide optimal isolation of the gas-producing zone from overlaying formations. The number of cemented casings and the depth ranges covered will depend on local geologic and hydrologic conditions. However, there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not.

Well integrity is an ideal example of where a best practice approach, adopted by the industry, can stress best practice and collect data to validate continuous improvement. The American Petroleum Institute, for example, has focused on well completion in its standards activity for shale gas production.[23]

At present, however, there is a wide range in procedures followed in the field with regard to casing placement and cementing for shale gas drilling. There are different practices with regard to completion testing and different regulations for monitoring possible gas leakage from the annulus at the wellhead. In some jurisdictions, regulators insist that gas leakage can be vented; others insist on containment with periodic pressure testing. There are no common leakage criteria for intervention in a well that exhibits damage or on the nature of the intervention. It is very likely that over time a focus on best practice in well completion will result in safer operations and greater environmental protection. The best practice will also avoid costly interruptions to normal operations. The regulation of shale gas development should also include inspections at safety-critical stages of well construction and hydraulic fracturing.

Limiting water use by controlling vertical fracture growth: – a second example. While the vertical growth of hydraulic fractures does not appear to have been a causative factor in reported cases where methane from shale gas formations has migrated to the near surface, it is in the best interest of operators and the public to limit the vertical extent of hydraulic fractures to the gas bearing shale formation being exploited. By improving the efficiency of hydraulic fractures, more gas will be produced using less water for fracturing – which has economic value to operators and environmental value for the public.

The vertical propagation of hydraulic fractures results from the variation of earth stress with depth and the pumping pressure during fracturing. The variation of earth stress with depth is difficult to predict, but easy to measure in advance of hydraulic fracturing operations. Operators and service companies should assure that through periodic direct measurement of earth stresses and microseismic monitoring of hydraulic fracturing operations, everything possible is being done to limit the amount of water and additives used in hydraulic fracturing operations.

Evolving best practices must be accompanied by metrics that permit tracking of the progress in improving shale gas operations performance and environmental impacts. The Subcommittee has the impression that the current standard- setting processes do not utilize metrics. Without such metrics and the collection of relevant measured data, operators lack the ability to track objectively the progress of the extensive process of setting and updating standards.

Research and development needs

The profitability, rapid expansion, and the growing recognition of the scale of the resource mean that oil and gas companies will mount significant R&D efforts to improve performance and lower cost of shale gas exploration and production. In general the oil and gas industry is a technology-focused and technology-driven industry, and it is safe to assume that there will be a steady advance of technology over the coming years.

In these circumstances the federal government has a limited role in supporting R&D. The proper focus should be on sponsoring R&D and analytic studies that address topics that benefit the public or the industry but which do not permit individual firms to attain a proprietary position. Examples are environmental and safety studies, risk assessments, resource assessments, and longer-term R&D (such as research on methane hydrates). Across many administrations, the Office of Management and Budget (OMB) has been skeptical of any federal support for oil and gas R&D, and many Presidents' budget have not included any request for R&D for oil and gas. Nonetheless Congress has typically put money into the budget for oil & gas R&D.

The following table summarizes the R&D outlays of the DOE, EPA, and USGS for unconventional gas:

Unconventional Gas R&D Outlays for Various Federal Agencies ($ millions)					
	FY2008	**FY2009**	**FY2010**	**FY2011**	**FY2012 request**
DOE Unconventional Gas					
EPAct Section 999 Program Funds					
RPSEA Administered	$14	$14	$14	$14	0
NETL Complementary	$9	$9	$9	$4	0
Annual Appropriated Program Funds					
Environmental	$2	$4	$2	0	0
Unconventional Fossil Energy	0	0	$6	0	0
Methane Hydrate projects	$15	$15	$15	$5	$10
Total Department of Energy	$40	$42	$46	$23	$10
Environmental Protection Agency	$0	$0	$1.9	$4.3	$6.1
USGS	$4.5	$4.6	$5.9	$7.4	$7.6
Total Federal R&D	**$44.5**	**$46.6**	**$53.8**	**$34.7**	**$23.7**

Near Term Actions:

The Subcommittee believes that given the scale and rapid growth of the shale gas resource in the nation’s energy mix, the federal government should sponsor some R&D for unconventional gas, focusing on areas that have public and industry wide benefit and addresses public concern. The Subcommittee, at this point, is only in a position to offer some initial recommendations, not funding levels or to assignment of responsibility to particular government agencies. The DOE, EPA, the USGS, and DOI Bureau of Land Management all have mission responsibility that justify a continuing, tailored, federal R&D effort.

RPSEA is the Research Partnership to Secure Energy for America, a public/private research partnership authorized by the 2005 Energy Policy Act at a level of $50 million from offshore royalties. Since 2007, the RPSEA program has focused on unconventional gas. The Subcommittee strongly supports the RPSEA program at its authorized level.[24]

The Subcommittee recommends that the relevant agencies, the Office of Science and Technology Policy (OSTP), and OMB discuss and agree on an appropriate mission and level of funding for unconventional natural gas R&D. If requested, the Subcommittee, in the second phase of its work, could consider this matter in greater detail and make recommendations for the Administration's consideration.

In addition to the studies mentioned in the body of the report, the Subcommittee mentions several additional R&D projects where results could reduce safety risk and environmental damage for shale gas operations:

1. Basic research on the relationship of fracturing and micro-seismic signaling.
2. Determination of the chemical interactions between fracturing fluids and different shale rocks – both experimental and predictive.
3. Understanding induced seismicity triggered by hydraulic fracturing and injection well disposal.[25]
4. Development of "green" drilling and fracturing fluids.
5. Development of improved cement evaluation and pressure testing wireline tools assuring casing and cementing integrity.

Longer term prospects for technical advance

The public should expect significant technical advance on shale gas production that will substantially improve the efficiency of shale gas production and that will in turn reduce environmental impact. The expectation of significant production expansion in the future offers a tremendous incentive for companies to undertake R&D to improve efficiency and profitability. The history of the oil and gas industry supports such innovation, in particular greater extraction of the oil and gas in place and reduction in the unit cost of drilling and production.

The original innovations of directional drilling and formation fracturing plausibly will be extended by much more accurate placement of fracturing fluid guided by improved interpretation of micro-seismic signals and improved techniques of reservoir testing. As an example, oil services firms are already offering services that provide near-real-time monitoring to avoid excessive vertical fracturing growth, thus affording better control of fracturing fluid placement. Members of the Subcommittee estimate that an improvement in in efficiency of water use could be between a factor of two and four. There will be countless other innovations as well.

There has already been a major technical innovation – the switch from single well to pad-based drilling and production of multiple wells (up to twenty wells per pad have been drilled). The multi-well pad system allows for enhanced efficiency because of repeating operations at the same site and a much smaller footprint (e.g. concentrated gas gathering systems; many fewer truck trips associated with drilling and completion, especially related to equipment transport; decreased needs for road and pipeline constructions, etc.). It is worth noting that these efficiencies may require pooling acreage into large blocks.

Conclusion

The public deserves assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. Nonetheless, accidents and incidents have occurred with shale gas development, and uncertainties about impacts need to be quantified and clarified. Therefore the Subcommittee has highlighted important steps for more thorough information, implementation of best practices that make use of technical innovation and field experience, regulatory enhancement, and focused R&D, to ensure that shale operations proceed in the safest way possible, with enhanced efficiency and minimized adverse impact. If implemented these measures will give the public reason to believe that the nation's considerable shale gas resources are being developed in a way that is most beneficial to the nation.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;

- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;
- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore.

More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

ENDNOTES

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[1] http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf

[2] The James Baker III Institute for Public Policy at Rice University has recently released a report on *Shale Gas and U.S. National Security,* Available at: http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf.

[3] As a shale of total dry gas production in the "lower '48", shale gas was 6 percent in 2006, 8 percent in 2007, at which time its share began to grow rapidly – reaching 12 percent in 2008, 16 percent in 2009, and 24 percent in 2010. In June 2011, it reached 29 percent. Source: Energy Information Adminstration and Lippman Consulting.

[4] Timothy Considine, Robert W. Watson, and Nicholas B. Considine, "The Economy Opportunities of Shale Energy Development," Manhattan Institute, May 2011, Table 2, page 6.

[5] Essentially all fracturing currently uses water at the working fluid. The possibility exists of using other fluids, such as nitrogen, carbon dioxide or foams as the working fluid.

[6] The Department of Energy has a shale gas technology primer available on the web at: http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

[7] See the Bureau of Land Management *Gold Book* for a summary description of the DOI's approach: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf

[8] http://www.shalegas.energy.gov/

[9] The 2011 *MIT Study on the Future of Natural Gas,* gives an estimate of about 50 widely reported incidents between 2005 and 2009 involving groundwater contamination, surface spills, off-site disposal issues, water issues, air quality and blow outs, Table 2.3 and Appendix 2E. http://web.mit.edu/mitei/research/studies/naturalgas.html

[10] The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission are considering a project to create a *National Oil and Gas Data Portal* with similar a objective, but broader scope to encompass all oil and gas activities.

[11] Information about STRONGER can be found at: http://www.strongerinc.org/

[12] The RBMS project is supported by the DOE Office of Fossil Energy, DOE grant #DE-FE0000880 at a cost of $1.029 million. The project is described at: http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000880_GWPC_Kickoff.pdf

[13] See, for example: John Corra, "Emissions from Hydrofracking Operations and General Oversight Information for Wyoming," presented to the U.S. Department of Energy Natural Gas Subcommittee of the Secretary of Energy Advisory Board, July 13, 2011; Al Armendariz, "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements," Southern Methodist University, January 2009; Colorado Air Quality Control Commission, "Denver Metro Area & North Front Range Ozone Action Plan," December 12, 2008; Utah Department of Environmental Quality, "2005 Uintah Basin Oil and Gas Emissions Inventory," 2005.

[14] IPCC 2007 –The Physical Science Basis, Section 2.10.2).

[15] Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, *Methane and the greenhouse-gas*

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footprint of natural gas from shale formations, Climate Change, The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material.

[16] Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States,* DOE, NETL, May 2011, available at: http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

[17] Paulina Jaramillo, W. Michael Griffin, and H. Scott Mathews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, 41, 6290-6296 (2007).

[18] The EPA draft hydraulic fracturing study plan is available along with other information about EPA hydraulic fracturing activity at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

[19] See, for example, "South Texas worries over gas industry's water use during drought," Platts, July 5, 2011, found at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3555776; "Railroad Commission, Halliburton officials say amount of water used for fracking is problematic," Abeline Reporter News, July 15, 2011, found at: http://www.reporternews.com/news/2011/jul/15/railroad-commission-halliburton-officials-say-of/?print=1; "Water Use in the Barnett Shale," Texas Railroad Commission Website, updated January 24, 2011, found at: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

[20] See, for example, *Energy Demands on Water Resources, DOE Report to Congress,* Dec 2006, http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf

[21] Stephen G. Osborna, Avner Vengoshb, Nathaniel R. Warnerb, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011).

[22] See EPA Certification Guidance for Engines Regulated Under: 40 CFR Part 86 (On-Highway Heavy-Duty Engines) and 40 CFR Part 89 (Nonroad CI Engines); available at: http://www.epa.gov/oms/regs/nonroad/equip-hd/420b98002.pdf

[23] API standards documents addressing hydraulic fracturing are: API HF1, Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition/October 2009, API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010, API HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, First Edition/January 2011, available at: http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm

[24] Professor Steven Holditch, one of the Subcommittee members, is chair of the RPSEA governing committee.

[25] Extremely small microearthquakes are triggered as an integral part of shale gas development. While essentially all of these earthquakes are so small as to pose no hazard to the public or facilities (they release energy roughly equivalent to a gallon of milk falling of a kitchen counter), earthquakes of larger (but still small) magnitude have been triggered during hydraulic fracturing operations and by the injection of flow-back water after hydraulic fracturing. It is important to develop a hazard assessment and remediation protocol for triggered earthquakes to allow operators and regulators to know what steps need to be taken to assess risk and modify, as required, planned field operations.

United States
Environmental Protection
Agency

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Technical Support Document for Proposed Standards

EPA-453/R-11-002
July 2011

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

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Contract No. EP-D-07-061
Work Order No. 4-06

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
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DISCLAIMER

FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector. The proposed standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, is appropriate, NSPS standards. The NSPS review allows EPA to identify processes in the oil and natural sector that are not regulated under the existing NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector. Chapter 3 discusses the entire NSPS review process undertaken for this review. Finally, Chapters 4-8 provide information on previously unregulated emissions sources. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided.

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APPENDIX A

1.0 NEW SOURCE PERFORMANCE STANDARD BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "…causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This technical support document (TSD) supports the proposed standards, which would control volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from the oil and natural gas sector.

1.1 Statutory Authority

Section 111 of the Clean Air Act (CAA) requires the Environmental Protection Agency Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of control is referred to as the best system of emission reduction (BSER). In determining BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are also evaluated. This analysis determines BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated a NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations. These NSPS are relatively narrow in scope as they address emissions only at natural gas processing plants. Specifically, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants, and subpart LLL addresses SO_2 emissions from natural gas processing plants.

1.3 NSPS Review Process Overview

CAA section 111(b)(1)(B) requires EPA to review and revise, if appropriate, NSPS standards. First, the existing NSPS were evaluated to determine whether it reflects BSER for the emission affected sources. This review was conducted by examining control technologies currently in use and assessing whether these technologies represent advances in emission reduction techniques compared to the technologies upon which the existing NSPS are based. For each new control technology identified, the potential emission reductions, costs, secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are evaluated. The second step is evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas sector that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare. The final review step is to identify additional processes in the oil and natural gas sector that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant (i.e. from the well to the natural gas processing plant) are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the "citygate." Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic hazardous air pollutants (HAP). The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas[i]

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

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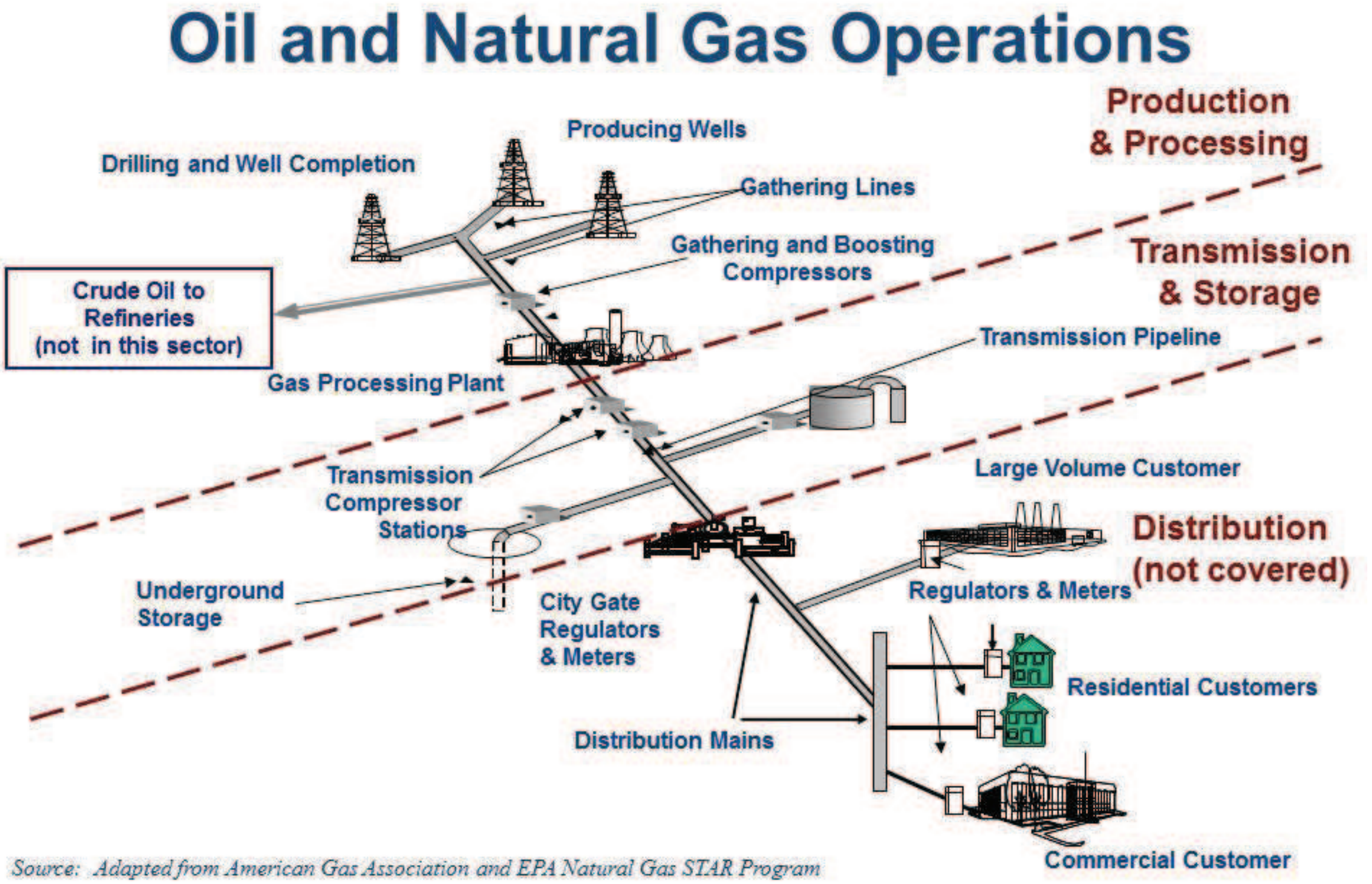
[i] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2



Source: *Adapted from American Gas Association and EPA Natural Gas STAR Program*

Figure 2-1. Oil and Natural Gas Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

As discussed in section 1.2, there are two NSPS that impact the oil and natural gas sector: (1) the NSPS for equipment leaks of VOC at natural gas processing plants (subpart KKK) and (2) the NSPS for SO_2 emissions from sweetening units located at natural gas processing plants (subpart LLL). Because they only address emissions from natural gas processing plants, these NSPS are relatively narrow in scope.

Section 111(b)(1) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consisted of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted by facilities in the oil and natural gas sector that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes in the oil and natural gas sector for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of BSER for Existing NSPS

Consistent with the obligations under CAA section 111(b), control options reflected in the current NSPS for the Oil and Natural Gas source category were evaluated in order to distinguish if these options still represent BSER. To evaluate the BSER options for equipment leaks the following was reviewed: EPA's current leak detection and repair (LDAR) programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.[1]

3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, the LDAR requirements in 40 CFR part 60, subpart VVa were also reviewed. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. Options based on optical gas imaging were also reviewed.

The currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. Although there have been advancements in the use of optical gas imaging to detect leaks from these same types of components, these instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In considering BSER for VOC equipment leaks at natural gas processing plants, four options were evaluated. One option evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, it was estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, the individual types of components (valves, connectors, pressure relief devices and open-ended lines) were also analyzed separately to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are provided in Chapter 8. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). It was previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on the emission reduction level, the cost effectiveness of this option was estimated to be $6,462 per ton of VOC reduction. This analysis was based on the facility purchasing an optical gas imaging system costing $85,000. However, at least one manufacturer was identified that rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 inspection visits is $4,638 per ton of VOC reduction.[i]

A third option evaluated consisted of monthly optical gas imaging without an annual Method 21 check. The annual cost of the monthly optical gas imaging LDAR program was estimated to be $76,581 based on camera purchase, or $51,999 based on camera rental. However, it is not possible to quantify the VOC emission reductions achieved by an optical imaging program alone, therefore the cost effectiveness of this option could not be determined. Finally, a fourth option was evaluated that was similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, the annual cost was estimated to be $43,851, based on camera purchase, or $18,479, based on camera rental.

Because the cost effectiveness of options 3 and 4 could not be estimated, these options could not be identified as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 achieve equivalent VOC reduction and are both cost effective, both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR.

3.1.2 BSER for SO_2 Emissions from Sweetening Units at Natural Gas Processing Plants

For 40 CFR part 60, subpart LLL, control systems for SO_2 emissions from sweetening units located at natural gas processing plants were evaluated, including those followed by a sulfur recovery unit. Subpart

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[i] Because optical gas imaging is used to view multiple pieces of equipment at a facility during one leak survey, options involving imaging are not amenable to a component by component analysis.

LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (i.e., H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

In addition, process modifications and tail gas treatment options were also evaluated at the time 40 CFR part 60, subpart LLL was proposed.[ii] As explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated.

As shown in the original evaluation for the proposed subpart LLL, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics.[iii] The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, a search was performed of the RBLC database[1] and state regulations. No State regulations were identified that included emission limitations more stringent than 40 CFR part 60, subpart LLL. However, two entries in the RBLC database were identified having SO_2

[ii] 49 FR 2656, 2659-2660 (1984).

[iii] 49 FR 2656, 2663-2664 (1984).

emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tailgas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a feed rate of 280 long tons of sulfur per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, the original data was reevaluated. Based on the available cost information, a 99.9 percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on this review, the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and a H_2S content equal to or greater than 50 percent is raised to 99.9 percent.

The search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, there were not any identifiable changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.[1]

3.2 Additional Pollutants

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are NESHAP that address air toxics from the oil and natural gas sector, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990 - 2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 MMtCO2e (million metric tons of CO2-equivalents (CO2e)).[iv] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory).

[iv] U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2009. http://www.epa.gov/climatechange/emissions/downloads10/US-GHGInventory2010_ExecutiveSummary.pdf

This adjustment would increase the 2009 Inventory estimate by 76.74 MMtCO2e. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 MMtCO2e.

Although this proposed rule does not include standards for regulating the GHG emissions discussed above, EPA continues to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_x emissions would be pit flaring of VOC emissions from well completions. As discussed in Chapter 4 Well completions, pit flaring is one option identified for controlling VOC emissions. Because there is no way of directly measuring the NO_x produced, nor is there any way of applying controls other than minimizing flaring, flaring would only be required for limited conditions.

3.3 Additional Processes

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where SO_2 is expected to be emitted directly; although H_2S contained in sour gas[v] forms SO_2 as a product of oxidation when oxidized in the atmosphere or combusted in boilers and heaters in the field. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (i.e., they have a heat

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[v] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

input of less than 10 million British Thermal Units per hour). They may, however, be included in future rulemakings.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. Pursuant to CAA section 111(b), a modification of the listed category will now include all segments of the oil and natural gas industry for regulation. In addition, VOC standards will now cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. In addition, produced water ponds may also be a potentially significant source of emissions, but there is very limited information available regarding these emissions. Therefore, no options could be evaluated at this time. The remainder of this document presents the evaluation for each of the new processes to be included in the NSPS.

3.4 References

1 Memorandum to Bruce Moore from Brad Nelson and Phil Norwood. Crude Oil and Natural Gas Production NSPS Technology Reviews. EC/R Incorporated. July 28, 2011.

4.0 WELL COMPLETIONS AND RECOMPLETIONS

In the oil and natural gas sector, well completions and recompletions contain multi-phase processes with various sources of emissions. One specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes completions and recompletions, and provides estimates for representative wells in addition to nationwide emissions. Control techniques employed to reduce emissions from flowback gas venting during completions and recompletions are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for reducing flowback emissions during completions and recompletions.

4.1 Process Description

4.1.1 Oil and Gas Well Completions

All oil and natural gas wells must be "completed" after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Conventional gas reservoirs have well defined formations with high resource allocation in permeable and porous formations, and wells in conventional gas reservoirs have generally not required stimulation during production. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract gas.[1]

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and gathering lines are installed as necessary for production to begin. The flowback stage of a well completion is highly variable but typically lasts between 3 and 10 days for the average well.[2]

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as “wildcat”) wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving gas production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that “props open” the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

Hydraulic fracturing can and does occur in some conventional reservoirs, but it is much more common in “tight” formations. Therefore, this analysis assumes hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations. This analysis defines tight sand as sandstones or carbonates with an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[i]

“Energized fractures” are a relatively new type of completion method that injects an inert gas, such as carbon dioxide or nitrogen, before the fracture fluid and proppant. Thus, during initial flowback, the gas stream will first contain a high proportion of the injected gas, which will gradually decrease overtime.

4.1.2 Oil and Gas Well Recompletions

Many times wells will need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include

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[i] A darcy (or darcy unit) and millidarcies (mD) are units of permeability Converted to SI units, 1 darcy is equivalent to 9.869233×10^{-13} m² or 0.9869233 (µm)². This conversion is usually approximated as 1 (µm)².

completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The backflow velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Backflow emissions are not a direct result of produced water. Backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the backflow emissions originate from the recompletion process but are vented as the backflow enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2. Emission Data and Emissions Factors

4.2.1 Summary of Major Studies and Emission Factors

Given the potential for significant emissions from completions and recompletions, there have been numerous recent studies conducted to estimate these emissions. In the evaluation of the emissions and emission reduction options for completions and recompletions, many of these studies were consulted. Table 4-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 [4,5]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute /US Environmental Protection Agency	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [13]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[14]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [15]	Environmental Defense Fund	2009	Regional	X	X
Emissions from Oil and Natural Gas Production Facilities [16]	Texas Commission for Environmental Quality	2007	Regional	X	X
Availability, Economics and Production of North American Unconventional Natural Gas Supplies 1	Interstate Natural Gas Association of America	2008	Nationwide		

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Petroleum and Natural Gas Statistical Data[17]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [18]	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program [19]	New York State Department of Environmental Conservation	2009	Regional	X	X
Natural Gas STAR Program [20, 21, 22, 23, 24, 25]	EPA	2000-2010	Nationwide/ Regional	X	X

4.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion and recompletion emissions are estimated as the venting of emissions from the well during the initial phases of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

As previously stated, this analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. A majority of the available emissions data for recompletions is for vertically drilled wells. It is projected that in the future, a majority of completions and recompletions will predominantly be performed on horizontal wells. However, there is not enough history of horizontally drilled wells to make a reasonable estimation of the difference in emissions from recompletions of horizontal versus vertical wells. Therefore, for this analysis, no distinction was made between vertical and horizontal wells.

As shown in Table 4-1, methane emissions from oil and natural gas operations have been measured, analyzed and reported in studies spanning the past few decades. The basic approach for this analysis was to approximate methane emissions from representative oil and gas completions and recompletions and then estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP) using a representative gas composition.[26] The specific gas composition ratios used for gas wells were 0.1459 pounds (lb) VOC per lb methane (lb VOC/lb methane) and 0.0106 lb HAP/lb methane. The specific gas composition ratios used for oil wells were 0.8374 pounds lb VOC/lb methane and 0.0001 lb HAP/lb methane.

The EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (Subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), was the foundation for methane emission estimates from natural gas completions with hydraulic fracturing and recompletions with hydraulic fracturing. Methane emissions from oil well completions, oil well recompletions, natural gas completions without hydraulic fracturing, and natural gas recompletions without hydraulic fracturing were derived directly from the EPA's Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 (Inventory).[4] A summary of emissions for a representative model well completion or recompletion is found in Table 4-2.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

Well Completion Category	**Emissions (Mcf/event)**	**Emissions (tons/event)**		
	Methane	**Methane**[a]	**VOC**[b]	**HAP**[c]
Natural Gas Well Completion without Hydraulic Fracturing	38.6	0.8038	0.12	0.009
Natural Gas Well Completion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Completions	0.34	0.0076	0.00071	0.0000006
Natural Gas Well Recompletion without Hydraulic Fracturing	2.59	0.0538	0.0079	0.0006
Natural Gas Well Recompletion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Recompletions	0.057	0.00126	0.001	0.0000001

Minor discrepancies may exist due to rounding.

a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.
b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.
c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

4.3 Nationwide Emissions from New Sources

4.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of the proposed rulemaking, referred to as the baseline emissions estimate. In order to develop the baseline emissions estimate, the number of completions and recompletions performed in a typical year was estimated and then multiplied by the expected uncontrolled emissions per well completion listed in Table 4-2. In addition, to ensure no emission reduction credit was attributed to sources already controlled under State regulations, it was necessary to account for the number of completions/recompletions already subject to State regulations as detailed below. In order to estimate the number of wells that are already controlled under State regulations, existing well data was analyzed to estimate the percentage of currently controlled wells. This percentage was assumed to also represent the wells that would have been controlled in absence of a federal regulation and applied to the number of well completions estimated for future years.

4.3.2 Number of Completions and Recompletions

The number of new well completions was estimated using the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. EIA is legally required to make the NEMS source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions.

New well completion estimates are based on predictions from the NEMS Oil and Gas Supply Model, drawing upon the same assumptions and model used in the Annual Energy Outlook 2011 Reference Case. New well completions estimates were based on total successful wells drilled in 2015 (the year of analysis for regulatory impacts) for the following well categories: natural gas completions without hydraulic fracturing, natural gas completions with hydraulic fracturing, and oil well completions.

Successful wells are assumed to be equivalent to completed wells. Meanwhile, it was assumed that new dry wells would be abandoned and shut in and would not be completed. Therefore estimates of the number of dry wells were not included in the activity projections or impacts discussion for exploratory and developmental wells. Completion estimates are based on successful developmental and exploratory wells for each category defined in NEMS that includes oil completions, conventional gas completions and unconventional gas completions. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. Since hydraulic fracturing is most common in unconventional formations, this analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. New successful natural gas wells in conventional formations are assumed to be completed without hydraulic fracturing.

The number of natural gas recompletions with hydraulic fracturing (also referred to as a re-fracture), natural gas recompletions without hydraulic fracturing and oil well recompletions was based on well count data found in the HPDI® database.[ii, iii] The HPDI database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. HPDI® collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. HPDI was used to estimate the number of recompleted wells because the historical well data from HPDI is a comprehensive resource describing existing wells. Well data from 2008 was used as a base year since it was the most recent available data at the time of this analysis and is assumed to represent the number of recompletions that would occur in a representative year. The number of hydraulically fractured natural gas recompletions was estimated by estimating each operator and field combination found in the HPDI database and multiplying by 0.1 to represent 10 percent of the wells being re-fractured annually (as assumed in Subpart W's Technical Supporting Document3). This results in 14,177 total natural gas recompletions with hydraulic fracturing in the U.S. for the year 2008; which is assumed to depict a representative year. Non-fractured

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[ii] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data.

[iii] For the State of Pennsylvania, the most recent drilling information available from HPDI was for 2003. Due to the growth of oil and gas operations occurring in the Marcellus region in Pennsylvania, this information would not accurately represent the size of the industry in Pennsylvania for 2006 through 2008. Therefore, information from the Pennsylvania's Department of Environmental Protection was used to estimate well completion activities for this region. Well data from remaining states were based on available information from HPDI. From <http://www.marcellusreporting.state.pa.us/OGREReports/Modules/DataExports/DataExports.aspx

recompletions were based on well data for 2008 in HPDI. The number of estimated well completions and recompletions for each well source category is listed in Table 4-3.

4.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it is first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. Therefore, the number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing State regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., wells impacted by these regulations were not included in this analysis because well count data are not available on a county or local ordinance level. Therefore, the percentage calculated based on the identified State regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under State regulations, EIA historical well count data was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the States identified as having existing controls.[iv] Colorado (CO) and Wyoming (WY) were the only States identified as requiring controls on completions prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared. [27] The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to WY, the Colorado Oil and Gas Conservation Commission (COOGCC) requires REC for both oil and natural gas wells.[28] It was assumed for this analysis that the ratio of natural wells in CO and WY to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in WY to the number of total nationwide wells

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[iv] See EIA's The Number of Producing Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm

Table 4-3: Estimated Number of Total Oil and Natural Gas Completions and Recompletions for a Typical Year

Well Completion Category	Estimated Number of Total Completions and Recompletions[a]	Estimated Number of Controlled Completions and Recompletions	Estimated Number of Uncontrolled Completions and Recompletions[b]
Natural Gas Well Completions without Hydraulic Fracturing[*]	7,694		7,694
Exploratory Natural Gas Well Completions with Hydraulic Fracturing[**]	446		446
Developmental Natural Gas Well Completions with Hydraulic Fracturing[c]	10,957	1,644	9,313
Oil Well Completions[d]	12,193		12,193
Natural Gas Well Recompletions without Hydraulic Fracturing	42,342		42,342
Natural Gas Well Recompletions with Hydraulic Fracturing[‡‡]	14,177	2,127	12,050
Oil Well Recompletions[‡]	39,375		39,375

a. Natural gas completions and recompletions without hydraulic fracturing are assumed to be uncontrolled at baseline.
b. Fifteen percent of natural gas well completions with hydraulic fracturing are assumed as controlled at baseline.
c. Oil well completions and recompletions are assumed to be uncontrolled at baseline.
d. Fifteen percent of natural gas well recompletions with hydraulic fracturing are assumed to be controlled at baseline.

was assumed to represent the percentage of controlled well recompletions as it was the only State identified as having regulations directly regulated to recompletions.

From this review it was estimated that 15 percent of completions and 15 percent of recompletions are controlled in absence of federal regulation. It is also assumed for this analysis that only natural gas wells undergoing completion or recompletion with hydraulic fracturing are controlled in these States. Completions and recompletions that are performed without hydraulic fracturing, in addition to oil well completions and recompletions were assumed to not be subject to State regulations and therefore, were assumed to not be regulated at baseline. Baseline emissions for the controlled completions and recompletions covered by regulations are assumed to be reduced by 95 percent from the use of both REC and combustion devices that may be used separately or in tandem, depending on the individual State regulation.[v] The final activity factors for uncontrolled completions and uncontrolled recompletions are also listed in Table 4-3.

4.3.4 Emission Estimates

Using the estimated emissions, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil and gas well completions and recompletions in a typical year were calculated and are summarized in Table 4-4. All values have been independently rounded to the nearest ton for estimation purposes. As the table indicates, hydraulic fracturing significantly increases the magnitude of emissions. Completions and recompletions without hydraulic fracturing have lower emissions, while oil completions and recompletions have even lower emissions in comparison.

4.4 Control Techniques

4.4.1 Potential Control Techniques

Two techniques were considered that have been proven to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the impacts of their application for a representative well. Nationwide impacts of chosen regulatory options are discussed in

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[v] Percentage of controls by flares versus REC were not determined, so therefore, the count of controlled wells with REC versus controlled wells with flares was not determined and no secondary baseline emission impacts were calculated.

Table 4-4. Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions

Well Completion Category	Uncontrolled Methane Emissions per event (tpy)	Number of Uncontrolled Wells[a]	Baseline Nationwide Emissions (tons/year)[a]		
			Methane[b]	VOC[c]	HAP[d]
Natural Gas Well Completions without Hydraulic Fracturing	0.8038	7,694	6,185	902	66
Exploratory Natural Gas Well Completions with Hydraulic Fracturing	158.55	446	70,714	10,317	750
Developmental Natural Gas Well Completions with Hydraulic Fracturing	158.55	9,313	1,476,664	215,445	15,653
Oil Well Completions	0.0076	12,193	93	87	.008
Natural Gas Well Recompletions without Hydraulic Fracturing	0.0538	42,342	2,279	332	24
Natural Gas Well Recompletions with Hydraulic Fracturing	158.55	12,050	1,910,549	278,749	20,252
Oil Well Recompletions	0.00126	39,375	50	47	.004

Minor discrepancies may be due to rounding.

a. Baseline emissions include emissions from uncontrolled wells plus five percent of emissions from controlled sources. The Baseline emission reductions listed in the Regulatory Impacts (Table 4-9) represents only emission reductions from uncontrolled sources.
b. The number of controlled and uncontrolled wells estimated based on State regulations.
c. Based on the assumption that VOC content is 0.1459 pounds VOC per pound methane for natural gas wells and 0.8374 pounds VOC per pound methane for oil wells This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.
d. Based on the assumption that HAP content is 0.0106 pounds HAP per pound methane for natural gas wells and 0.0001 pounds HAP per pound methane for oil wells. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.

section 4.5.

4.4.2 Reduced Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as “green” or “flareless” completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.[29] In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[30] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.

- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

4.4.2.2. Effectiveness

RECs are an effective emissions reduction method for only natural gas completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[31] Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

4.4.2.3 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

Costs of performing a REC are projected to be between $700 and $6,500 per day, with representative well completion flowback lasting 3 to 10 days.2 This cost range is the incremental cost of performing a REC over a traditional completion, where typically the gas is vented or combusted because there is an absence of REC equipment. Since RECs involve techniques and technologies that are new and continually evolving, and these cost estimates are based on the state of the industry in 2006 (adjusted to 2008 US dollars). [vi] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback.
- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion.

Costs were assessed based on an average of the above data (for costs and number of days per completion), resulting in an average incremental cost for a REC of $4,146 per day (2008 dollars) for an average of 7 days per completion. This results in an overall incremental cost of $29,022 for a REC versus an uncontrolled completion. An additional $691 (2008 dollars) was included to account for transportation and placement of equipment, bringing total incremental costs estimated at $29,713. Reduced emission completions are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. Dividing by the expected emission reductions, cost-effectiveness for VOC is $1,429 per ton, with a methane co-benefit of $208 per ton. Table 4-5 provides a summary of REC cost-effectiveness.

Monetary savings associated with additional gas captured to the sales line was also estimated based on a natural gas price of $4.00[vii] per thousand cubic feet (Mcf).[32] It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates

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[vi] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

[vii] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the price, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings. The value of natural gas condensate recovered during the REC would also be significant depending on the gas composition. This value was not incorporated into the monetary savings in order to not overstate savings.

Table 4-5. Reduced Emission Completion and Recompletion Emission Reductions and Cost Impacts Summary

Well Completion Category	**Emission Reduction Per Completion/Recompletion (tons/year)**[a]			**Total Cost Per Completion/ Recompletion**[b] **($/event)**	**VOC Cost Effectiveness ($/ton)**[c]		**Methane Cost Effectiveness ($/ton)**	
	VOC	**Methane**	**HAP**		**without savings**	**with savings**	**without savings**	**with savings**
Natural Gas Completions and Recompletions with Hydraulic Fracturing	20.8	142.7	1.5	29,713	1,429	net savings	208	net savings

Minor discrepancies may be due to rounding.

a. This represents a ninety percent reduction from baseline for the average well.

b. Total cost for reduced emission completion is expressed in terms of incremental cost versus a completion that vents emissions. This is based on an average incremental cost of $4,146 per day for an average length of completion flowback lasting 7 days and an additional $691 for transportation and set up.

c. Cost effectiveness has been rounded to the nearest dollar.

to a total recovery of 8,258 Mcf of natural gas per completion or recompletion with hydraulic fracturing. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately $33,030. In addition we estimate an average of 34 barrels of condensate is recovered per completion or recompletion. Assuming a condensate value of $70 per barrel (bbl), this result is an income due to condensate sales around $2,380.[33] When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net savings on the order of $5,697 per completion.

4.4.2.4 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[34] Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[35] Completion combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Effectiveness

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes use of a continuous ignition source with an independent external fuel supply is assumed to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a flare or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to flare unrecoverable gas safely in every case.

Federal regulations require industrial flares meet a combustion efficiency of 98 percent or higher as outlined in 40 CFR 60.18. This statute does not apply to completion combustion devices. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.[30, 36, 37] The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Impacts

An analysis depicting the cost for wells including completion combustion devices was conducted for the Petroleum Services Association of Canada (PSAC) [38] in 2009 by N.L. Fisher Supervision and Engineering, Ltd.[viii] The data corresponds to 34 gas wells for various types of formations, including coal bed methane and shale. Multiple completion methods were also examined in the study including hydraulic and energized fracturing. Using the cost data points from these natural gas well completions,

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[viii] It is important to note that outliers were excluded from the average cost calculation. Some outliers estimated the cost of production flares to be as low as $0 and as high as $56,000. It is expected that these values are not representative of typical flare costs and were removed from the data set. All cost data found in the PSAC study were aggregated values of the cost of production flares and other equipment such as tanks. It is possible the inclusion of the other equipment is not only responsible for the outliers, but also provides a conservatively high estimate for completion flares.

an average completion combustion device cost is approximately \$3,523 (2008 dollars).[ix] As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 4-6. Completion combustion devices have a cost-effectiveness of \$161 per ton VOC and a co-benefit of \$23 per ton methane for completions and recompletions with hydraulic fracturing.

4.4.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur oxides (SO_x, carbon dioxide (CO_2), and smoke/particulates (PM). The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[34] Due to the high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.[34]

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing

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[ix] The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals 521.9. The 2009 average value for the combustion device is \$3,195.

Table 4-6. Emission Reduction and Cost-effectiveness Summary for Completion Combustion Devices

Well Completion Category	Emission Reduction Per Completion/Workover (tons/year)[a]			Total Capital Cost Per Completion Event ($)*	VOC Cost Effectiveness	Methane Cost Effectiveness
	VOC	Methane	HAP		($/ton)[b]	($/ton)
Natural Gas Well Completions without Hydraulic Fracturing	0.11	0.76	0.0081	3,523	31,619	4,613
Natural Gas Well Completions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Completions	0.01	0.007	0.0000007		520,580	488,557
Natural Gas Well Recompletions without Hydraulic Fracturing	0.007	0.051	0.0005		472,227	68,889
Natural Gas Well Recompletions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Recompletions	0.00	0.001	0.0000001		3,134,431	2,941,615

Minor discrepancies may be due to rounding.

a. This assumes one combustion device will control one completion event per year. This should be considered a conservative estimate, since it is likely multiple completion events will be controlled with the same combustion unit in any given year. Costs are stated in 2008 dollars.

80 percent propylene and 20 percent propane.[34] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided are provided in Table 4-7.

Since this analysis assumed pit flares achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the pit flare plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and CO) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.5 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and PM from the combustion of the completion gases in the flare, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1: Require completion combustion devices for conventional natural gas well completions and recompletions;
- Regulatory Option 2: Require completion combustion devices for oil well completions and recompletions;
- Regulatory Option 3: Require combustion devices for all completions and recompletions;
- Regulatory Option 4: Require REC for all completions and recompletions of hydraulically fractured wells;
- Regulatory Option 5: Require REC and combustion operational standards for natural gas well completions with hydraulic fracturing, with the exception of exploratory, and delineation wells;
- Regulatory Option 6: Require combustion operational standards for exploratory and delineation wells; and

Table 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor (lb/10^6 Btu)
Total Hydrocarbon[b]	0.14
Carbon Monoxide	0.37
Nitrogen Oxides	0.068
Particular Matter[c]	0-274
Carbon Dioxide[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as methane equivalent.
c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
d. Carbon dioxide is measured in kg CO2/MMBtu and is derived from the carbon dioxide emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

- Regulatory Option 7: Require REC and combustion operational standards for all natural gas well recompletions with hydraulic fracturing.

The following sections discuss these regulatory options.

4.5.1 Evaluation of Regulatory Options

The first two regulatory options (completion combustion devices for conventional natural gas well completions and recompletions and completion combustion devices for oil well completions and recompletions) were evaluated first. As shown in Table 4-6, the cost effectiveness associated with controlling conventional natural gas and oil well completions and recompletions ranges from $31,600 per ton VOC to over $3.7 million per ton VOC. Therefore, Regulatory Options 1 and 2 were rejected due to the high cost effectiveness.

The next regulatory option, to require completion combustion devices for all completions and recompletions, was considered. Under Regulatory Option 3, all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., nitrogen oxides, carbon monoxide, etc.). Therefore, Regulatory Option 3 was also rejected.

The fourth regulatory option would require RECs for all completions and recompletions of hydraulically fractured wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 4 was rejected.

The fifth regulatory option was to require an operational standard consisting of a combination of REC and combustion for natural gas well completions with hydraulic fracturing. As discussed for Regulatory Option 4, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations. In order to allow for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g, wellhead pressure or inert gas concentrations), Regulatory Option 5 also allows for the use of a completion combustion device in combination with RECs.

Under Regulatory Option 5, a numerical limit was considered, but was rejected in favor of an operational standard. Under section 111(h)(2) of the CAA, EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

> "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
>
> (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

As discussed in section 4.4.3, emissions from a completion combustion device cannot be measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 5 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to pipelines. Section 111(b)(2) of the CAA allows EPA to "…distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing…." performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different "type" of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: *Subcategory 1* wells are all natural gas wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. *Subcategory 2* wells are natural gas wells that meet the following definitions of exploratory or delineation wells:

- Exploratory wells are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or

- Delineation wells means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 5 would apply to the Subcategory 1 wells and a sixth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 6 requires an operational standard for combustion for the Subcategory 2 wells. As described above, REC is not an option for exploratory and delineation wells due to their distance from sales lines. As with the Regulatory Option 5, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 5, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

The final regulatory option was considered for recompletions. Regulatory Option 7 requires an operational standard for a combination of REC and a completion combustion device for all recompletions with hydraulic fracturing performed on new and existing natural gas wells. Regulatory Option 7 has the same requirements as Regulatory Option 5. Subcategorization similar to Regulatory Option 5 was not necessary for recompletions because it was assumed that RECs would be technically feasible for recompletions at all types of wells since they occur at wells that are producing and thus proximity to a sales line is not an issue. While evaluating this regulatory option, it was considered whether or not recompletions at existing wells should be considered modifications and subject to standards.

The affected facility under the New Source Performance Standards (NSPS) is considered to be the wellhead. Therefore, a new well drilled after the proposal date of the NSPS would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS would not be subject to emission control requirements unless they underwent a modification after the proposal date. Under section 111(a) of the Clean Air Act, the term “modification” means:

> "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. Therefore, Regulatory Option 7 applies to recompletions using hydraulic fracturing at new and existing wells.

In summary, Regulatory Options 1, 2, 3, and 4 were determined to be unreasonable due to cost considerations, other impacts or technical feasibility and thereby rejected. Regulatory Options 5, 6, and 7 were determined to be applicable to natural gas wells and were evaluated further.

4.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Options 5, 6, and 7 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 5, 6, and 7 were selected as options for setting standards for completions and regulatory options as follows:

- Regulatory Option 5: Operational standard for completions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.

- Regulatory Option 6: An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.

- Regulatory Option 7: An operational standard equivalent to Regulatory Option 5 which applies to recompletions with hydraulic fracturing at new and existing wells.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. It was estimated that there would be 9,313 uncontrolled developmental natural gas well completions with hydraulic fracturing subject to Regulatory Option 5. Regulatory Option 6 would apply to 446 uncontrolled exploratory natural gas well completions with hydraulic fracturing, and 12,050 uncontrolled recompletions at existing wells would be subject to Regulatory Option 7.[x]

Table 4-8 presents the nationwide emission reduction estimates for each regulatory option. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

Cost impacts of the individual control techniques (RECs and completion combustion devices) were presented in section 4.4. For Regulatory Option 6, the costs for completion combustion devices presented in Table 4-6 for would apply to Subcategory 2 completions. The cost per completion event was estimated to be $3,523. Applied to the 446 estimated Subcategory 2 completions, the nationwide costs were estimated to be $1.57 million. Completion combustion devices are assumed to achieve an overall 95 percent combustion efficiency. Since the operational standards for Regulatory Options 5 and 7 include both REC and completion combustion devices, an additional cost impact analysis was

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[x] The number of uncontrolled recompletions at new wells is not included in this analysis. Based on the assumption that wells are recompleted once every 10 years, any new wells that are drilled after the date of proposal of the standard would not likely be recompleted until after the year 2015, which is the date of this analysis. Therefore, impacts were not estimated for recompletion of new wells, which will be subject to the standards.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

Well Completion Category	Number of Sources subject to NSPS[a]	Annual Cost Per Completion Event ($)[b]	Nationwide Emission Reductions (tpy)[c]			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 5 (operational standard for REC and combustion)												
Subcategory 1: Natural gas Completions with Hydraulic Fracturing	9,313	33,237	204,134	1,399,139	14,831	1,516	net savings	221	net savings	309.5	309.5	(20.24)
Regulatory Option 6 (operational standard for combustion)												
Subcategory 2: Natural gas Completions with Hydraulic Fracturing	446	3,523	9,801	67,178	712	160	160	23	23	1.57	1.57	1.57
Regulatory Option 7 (operational standard for REC and combustion)												
Natural Gas Well Recompletions with Hydraulic Fracturing	12,050	33,237	264,115	1,810,245	19,189	1,516	net savings	221	net savings	400.5	400.5	(26.18)

Minor discrepancies may be due to rounding.

a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
b. Costs per event for Regulatory Options 5 and 7 are calculated by adding the costs for REC and completion combustion device presented in Tables 4-5 and 4-6, respectively. Cost per event for Regulatory Option 6 is presented for completion combustion devices in Table 4-6.
c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.

performed to analyze the nationwide cost impacts of these regulatory options. The total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around $33,237, which includes the costs in Table 4-5 for the REC equipment and transportation in addition to the costs in Table 4-6 for the completion combustion device. Applying the cost for the combined REC and completion combustion device to the estimated 9,313 Subcategory 1 completions, the total nationwide cost was estimated to be $309.5 million, with a net annual savings estimated around $20 million when natural gas savings are considered. A cost of $400.5 million was estimated for recompletions, with an overall savings of around $26 million when natural gas savings are considered. The VOC cost effectiveness for Regulatory Options 5 and 7 was estimated at around $1,516 per ton, with a methane co-benefit of $221 per ton.

4.5.2.3 Secondary Impacts

Regulatory Options 5, 6 and 7 all require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although, it is understood the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 5 and 7, it was assumed that ninety percent of flowback is captured and an additional five percent of the remaining gas is combusted. For both Subcategory 1 natural gas well completions with hydraulic fracturing and for natural gas well recompletions with hydraulic fracturing, it is assumed around 459 Mcf of natural gas is combusted on a per well basis. For Regulatory Option 6, Subcategory 2 natural gas completions with hydraulic fracturing, it is assumed that 95 percent (8,716 Mcf) of flowback emissions are consumed by the combustion device. Tons of pollutant per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 4-7.

From category 1 well completions and from recompletions, it is estimated 0.02 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. From category 2 well completions, it is estimated 0.32 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions, the proposed regulatory options are estimated to produce around 507 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 4-9 summarizes the estimated secondary emissions of the selected regulatory options.

Table 4-9 Nationwide Secondary Impacts of Selected Regulatory Options[a]

Pollutant	Regulatory Options 5[b]		Regulatory Option 6[c]		Regulatory Options 7[b]	
	Subcategory 1 Natural Gas Well Completions with Hydraulic Fracturing		Subcategory 2 Natural Gas Well Completions with Hydraulic Fracturing		Natural Gas Well Recompletions with Hydraulic Fracturing	
	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)
Total Hydrocarbons	0.03	326	0.66	296	0.03	422
Carbon Monoxide	0.09	861	1.76	783	0.09	1,114
Nitrogen Oxides	0.02	158	0.32	144	0.02	205
Particulate Matter	0.00000002	0.0002	0.011	5	0.00000002	0.0003
Carbon Dioxide	33.06	307,863	628	280,128	33.06	398,341

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The operational standard (Regulatory Options 5 and 7) combines REC and combustion is assumed to capture 90 percent of flowback gas. Five percent of the remaining flowback is assumed to be consumed in the combustion device. Therefore, it is estimated 459 Mcf is sent to the combustion device per completion event. This analysis assumes there are 9,313 Subcategory 1 wells and 12,050 recompletions.

c. Assumes 8,716 Mcf of natural gas is sent to the combustion unit per completion. This analysis assumes 446 exploratory wells fall into this category.

d. Based on 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas.

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves. This chapter describes pneumatic devices including their function and associated emissions. Options available to reduce emissions from pneumatic devices are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic devices.

5.1 Process Description

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[1]

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) snap-acting devices release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized "closed loop" systems are applicable only in instances with very low pressure[2] and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Snap-acting controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from snap-acting devices is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the device's bleed stream. Since actuation emissions serve the device's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e. the bleed rate) and do not include emissions directly resulting from actuation. Snap-acting controllers are assumed to have zero bleed emissions. Most applications (but not all), snap-acting devices serve functionally different purposes than bleed devices. Therefore, snap-acting controllers are not further discussed in this analysis.

In addition, not all pneumatic controllers are gas driven. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic devices can be used. These "non-gas driven" pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not gas driven, they do not directly release natural gas or VOC emissions. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas driven devices.[9] The application of electrical controls is further elaborated in Section 5.3.

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic devices and the potential options available to reduce these emissions, numerous studies were consulted. Table 5-1 lists these references with an indication of the type of relevant information contained in each study.

5.2.2 Representative Pneumatic Device Emissions

Bleeding pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.[i]

For this analysis, EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the Greenhouse Gas Reporting rule, as well as obtained updated data from major vendors of pneumatic devices. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[3,ii] While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the

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[i] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled “Unaccounted for Gas Project Summary Volume.” This classification was adopted for the October 1993 Report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. As described on page 2-16 of the report, “devices with emissions or ‘bleed’ rates of 0.1 to 0.5 cubic feet per minute are considered to be ‘high-bleed’ types (PG&E 1990).” This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[ii] All rates are listed at an assumed supply gas pressure of 20 psig.

Table 5-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2009 [4, 5]	EPA	2011	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute / EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program[1]	EPA	2000-2010		X	X

prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. Therefore, for this analysis, EPA determined that best available emissions estimates for pneumatic devices are presented in Table W-1A and W-1B of the Greenhouse Gas Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W). However, for the natural gas processing segment, a more conservative approach was assumed since it has been determined that natural gas processing plants would have sufficient electrical service to upgrade to non-gas driven controls. Therefore, to quantify representative emissions from a bleed-device in the natural gas processing segment, information from Volume 12 of the EPA/GRI report[iii] was used to estimate the methane emissions from a single pneumatic device by type.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic device type in each industry segment and then estimate VOC and hazardous air pollutants (HAP) using a representative gas composition.[13] The specific ratios from the gas composition were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

5.3 Nationwide Emissions from New Sources

5.3.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined for each segment of the industry including natural gas production, natural gas processing, natural gas transmission and storage, and oil production. The methodologies that determined the estimated number of new devices installed in a typical year is provided in section 5.3.2 of this chapter.

5.3.2 Population of Devices Installed Annually

In order to estimate the average number of pneumatic devices installed in a typical year, each industry

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[iii] Table 4-11. page 56. epa.gov/gasstar/tools/related.html

Table 5-2. Average Bleed Emission Estimates per Pneumatic Device in the Oil and Natural Gas Sector (tons/year)[a]

Industry Segment	High-Bleed			Low-Bleed		
	Methane	**VOC**	**HAP**	**Methane**	**VOC**	**HAP**
Natural Gas Production[b]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Transmission and Storage[c]	3.20	0.089	0.003	0.24	0.007	0.0002
Oil Production[d]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Processing[e]	1.00	0.28	0.01	1.00	0.28	0.01

Minor discrepancies may be due to rounding.

a. The conversion factor used in this analysis is 1 thousand cubic feet of methane (Mcf) is equal to 0.0208 tons methane. Minor discrepancies may be due to rounding.
b. Natural Gas Production methane emissions are derived from Table W-1A and W-1B of Subpart W.
c. Natural gas transmission and storage methane emissions are derived from Table W-3 of Subpart W.
d. Oil production methane emissions are derived from Table W-1A and W-1B of Subpart W. It is assumed only continuous bleed devices are used in oil production.
e. Natural gas processing sector methane emissions are derived from Volume 12 of the 1996 GRI report.[9] Emissions from devices in the processing sector were determined based on data available for snap-acting and bleed devices, further distinction between high and low bleed could not be determined based on available data.

segment was analyzed separately using the best data available for each segment. The number of facilities estimated in absence of regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low bleed controllers, such as in Wyoming and Colorado.

For the natural gas production and oil production segments, the number of new pneumatics installed in a typical year was derived using a multiphase analysis. First, data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the ratio of pneumatic controllers installed per well site on a regional basis. These ratios were then applied to the number of well completions estimated in Chapter 4 for natural gas well completions with hydraulic fracturing, natural gas well completions without hydraulic fracturing and for oil well completions. On average, one pneumatic device was assumed to be installed per well completion for a total of 33,411 pneumatic devices. By applying the estimated 51 percent of bleed devices (versus snap acting controllers), it is estimated that an average of 17,040 bleed-devices would be installed in the production segment in a typical year.

The number of pneumatic controllers installed in the transmission segment was approximated using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g. 2007) from the given year's total (e.g. 2008). This difference was assumed to be the number of new devices installed in the latter year (e.g. Number of new devices installed during 2008 = Pneumatics in 2008 – Pneumatics in 2007). A 3-year average was calculated based on the number of new devices installed in 2006 through 2008 in order to determine the average number of new devices installed in a typical year.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of snap-acting devices that would be installed versus a bleed device. This estimate of the percent of snap-acting and bleed devices was based on raw data found in the GRI study, where 51 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission segment.9 The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 5-3 summarizes the estimated number of new devices installed per year.

Table 5-3. Estimated Number of Pneumatic Devices Installed in an Typical Year

Industry Segment	**Number of New Devices Estimated for a Typical Year**[a]		
	Snap-Acting	**Bleed-Devices**	**Total**
Natural Gas and Oil Production[b]	16,371	17,040	33,411
Natural Gas Transmission and Storage[c]	178	84	262

a. National averages of population counts from the Inventory were refined to include the difference in snap-acting and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 51 percent of the pneumatic controllers are bleed devices in the production segment, while 32 percent are bleed devices in the transmission segment.

b. The number of pneumatics was derived from a multiphase analysis. Data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the number of pneumatics per well on a regional basis. These ratios were applied to the number of well completions estimated in Chapter 4 for natural gas wells with hydraulic fracturing, natural gas wells without hydraulic fracturing and for oil wells.

c. The number of pneumatics estimated for the transmission segment was approximated from comparing a 3 year average of new devices installed in 2006 through 2008 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e. an instrument air system) and any high-bleed devices that remain are safety related. As a result, the number of new pneumatic bleed devices installed at existing natural gas processing plants was estimated as negligible. A new greenfield natural gas processing plant would require multiple control loops. In Chapter 8 of this document, it is estimated that 29 new and existing processing facilities would be subject to the NSPS for equipment leak detection. In order to quantify the impacts of the regulatory options represented in section 5.5 of this Chapter, it is assumed that half of these facilities are new sites that will install an instrument air system in place of multiple control valves. This indicates about 15 instrument air systems will be installed in a representative year.

5.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 5-4 by industry segment and device type. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table 5-2 per industry segment since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

5.4 Control Techniques

Although pneumatic devices have relatively small emissions individually, due to the large population of these devices installed on an annual basis, the cumulative VOC emissions for the industry are significant. As a result, several options to reduce emissions have been developed over the years. Table 5-5 provides a summary of these options for reducing emissions from pneumatic devices including: instrument air, non-gas driven controls, and enhanced maintenance.

Given the various control options and applicability issues, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic device emissions. This is also supported by States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed devices are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis. Although snap-acting devices have zero bleed emissions, this analysis assumes the

Table 5-4. Nationwide Baseline Emissions from Representative Pneumatic Device Installed in a Typical Year for the Oil and Natural Gas Industry (tons/year)[a]

Industry Segment	Baseline Emissions from Representative New Unit (tpy)			Number of New Bleed Devices Expected Per Year	Nationwide Baseline Emissions from Bleeding Pneumatic (tpy)[b]		
	VOC	Methane	HAP		VOC	Methane	HAP
Oil and Gas Production	1.9213	6.9112	0.0725	17,040	32,739	117,766	1,237
Natural Gas Transmission and Storage	0.09523	3.423	0.003	84	8	288	0.2

Minor discrepancies may be due to rounding.

a. Emissions have been based on the bleed rates for a high-bleed device by industry segment. Minor discrepancies may be due to rounding.

b. To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment.

Table 5-5. Alternative Control Options for Pneumatic Devices

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around $165 more than high bleed versions.
Convert to Instrument Air[14]	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back-up natural gas pneumatic device. These systems can achieve 100 percent reduction in emissions.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed device[15]	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.
Enhanced Maintenance[16]	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

devices are not always used in the same functional application as bleed devices and are, therefore, not an appropriate form of control for all bleed devices. It is assumed snap-acting, or no-bleed, devices meet the definition of a low-bleed. This concept is further detailed in Section 5.5 of this chapter. Since this analysis has assumed areas with electrical power have already converted applicable pneumatic devices to instrument air systems, instrument air systems are also described for natural gas processing plants only. Given applicability, efficiency and the expected costs of the other options identified in Table 5-5 (i.e. mechanical controls and enhanced maintenance), were not further conducted for this analysis.

5.4.1 Low-Bleed Controllers

5.4.1.1 Emission Reduction Potential

As discussed in the above sections, low-bleed devices provide the same functional control as a high-bleed device, but have lower continuous bleed emissions. As summarized in Table 5-6, it is estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low-bleed device in place of a high-bleed device. In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device available on the current market.

5.4.1.1 Effectiveness

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production and transmission and storage industry segments.[1] This corresponds to 13,632 new high-bleed devices in the production segment (out of 17,040) and 67 new high-bleed devices in the transmission and storage segment (out of 84) that can be replaced with a new low-bleed alternative. For high-bleed devices in natural gas processing, this analysis assumed that the replaceable devices have already been replaced with instrument air and the remaining high-bleed devices are safety related for about half of the existing processing plants.

Table 5-6. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Device with a Representative Low-Bleed Pneumatic Device

Segment/Device Type	Emissions (tons/year)[a]		
	Methane	VOC	HAP
Oil and Natural Gas Production	6.65	1.85	0.07
Natural Gas Transmission and Storage	2.96	0.082	0.002

Minor discrepancies may be due to rounding.

a. Average emission reductions for each industry segment based on the typical emission flow rates from high-bleed and low-bleed devices as listed in Table 5-2 by industry segment.

Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

Safety concerns may be a limitation issue, but only in specific situations because emergency valves are not bleeding controllers since safety is the pre-eminent consideration. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[iv] the equipment in place for such an event is spring loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

5.4.1.2 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research described in Section 5.2 as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.[1] As Table 5-7 indicates, the average cost for a low bleed pneumatic is \$2,553, while the average cost for a high bleed is \$2,338.[v] Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of \$165 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was

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[iv] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

[v] Costs are estimated in 2008 U.S. Dollars.

Table 5-7. Cost Projections for the Representative Pneumatic Devices[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low-Bleed Incremental Cost ($)
High-bleed controller	366	7,000	2,388	$165
Low-bleed controller	524	8,852	2,553	

a. Major pneumatic devices vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

annualized for a 10 year period using a 7 percent interest rate. This equated to an annualized cost of around $23 per device for both the production and transmission segments.

Monetary savings associated with additional gas captured to the sales line was estimated based on a natural gas value of $4.00 per Mcf.[vi,17] The representative low-bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high-bleed device per year. Assuming production quality gas is 82.8 percent methane by volume, this equals 385.5 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic device in the production segment equates to approximately $1,500. Savings were not estimated for the transmission segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. Table 5-8 provides a summary of low-bleed pneumatic cost effectiveness.

5.4.1.3 Secondary Impacts

Low-bleed pneumatic devices are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of low-bleed pneumatic devices.

5.4.2 Instrument Air Systems

5.4.2.1 Process Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank.

[vi] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

Table 5-8. Cost-effectiveness for Low-Bleed Pneumatic Devices versus High Bleed Pneumatics

Segment	Incremental Capital Cost Per Unit ($)[a]	Total Annual Cost Per Unit ($/yr)[b]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with savings	without savings	with savings	without savings	with savings
Oil and Natural Gas Production	165	23.50	-1,519	13	net savings	4	net savings
Natural Gas Transmission and Storage	165	23.50	23.50	286	286	8	8

a. Incremental cost of a low bleed device versus a high bleed device as summarized in Table 5-7.
b. Annualized cost assumes a 7 percent interest rate over a 10 year equipment lifetime.

For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

- A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.
- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available.[14]

5.4.2.2 Effectiveness

The use of instrument air eliminates natural gas emissions from the natural gas driven pneumatic devices; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning.[14]

5.4.2.3 Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation – adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop.[14] As the system is powered by electric compressors, the system requires a constant source of electrical power or a back-up pneumatic device. Table 5-9 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air"[14] and summarized in Table 5-10.[vii]

For natural gas processing, the cost-effectiveness of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air

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[vii] Costs have been converted to 2008 US dollars using the Chemical Engineering Cost Index.

Table 5-9. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			**Flow Rate**	**Control Loops**
Size of Unit	hp	kW	(cfm)	Loops/Compressor
small	10	13.3	30	15
medium	30	40	125	63
large	75	100	350	175

a. Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*[14]

b. Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

Table 5-10 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

a. Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

b. The annualized cost was estimated using a 7 percent interest rate and 10 year equipment life.

c. Annual Costs include the cost of electrical power as listed in Table 5-9 and labor.

unless the function has a specific need for a bleeding device, which would most likely be safety related.[9] Table 5-11 summarizes the cost-effectiveness of the three sizes of representative instrument air systems.

5.4.2.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

5.5 Regulatory Options

The affected facility definition for pneumatic controllers is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1: Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2: Establish an emissions limit equal to 6 scfh.

5.5.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely install instrument air systems to meet the threshold limit. This option is considered cost effective for natural gas processing plants as summarized in Table 5-11. A major assumption of this analysis, however, is that processing plants are constructed at a location with sufficient electrical service to power the instrument air compression system. It is assumed that facilities located outside of the processing plant would not have sufficient electrical service to install an instrument air system. This would significantly increase the cost of the system at these locations, making it not cost effective for these facilities to meet this regulatory option. Therefore, Regulatory Option 1 was accepted for natural gas processing plants and rejected for all other types of facilities.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the production and transmissions and storage industry segments. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria

Table 5-11 Cost-effectiveness of Representative Instrument Air Systems in the Natural Gas Processing Segment

System Size	Number of Control Loops	Annual Emissions Reduction[a] (tons/year)			Value of Product Recovered ($/year)[b]	Annualized Cost of System		VOC Cost-effectiveness ($/ton)		Methane Cost-effectiveness ($/ton)	
		VOC	CH_4	HAP		without savings	with savings	without savings	with savings	without savings	with savings
Small	15	4.18	15	0.16	3,484	11,090	7,606	2,656	1,822	738	506
Medium	63	17.5	63	0.66	14,632	36,877	22,245	2,103	1,269	585	353
Large	175	48.7	175	1.84	40,644	80,515	39,871	1,653	819	460	228

Minor discrepancies may be due to rounding.

a. Based on the emissions mitigated from the entire system, which includes multiple control loops.

b. Value of recovered product assumes natural gas processing is 82.8 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

would be required to ensure the device function dictates the precision of a high bleed device. Therefore, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

5.5.2 Nationwide Impacts of Regulatory Options

Table 5-12 summarizes the costs impacts of the selected regulatory options by industry segment. Regulatory Option 1 for the natural gas processing segment is estimated to affect 15 new processing plants with nationwide annual costs discounting savings of $166,000. When savings are realized the net annual cost is reduced to around $114,000. Regulatory Option 2 has nationwide annual costs of $320,000 for the production segment and around $1,500 in the natural gas transmission and storage segment. When annual savings are realized in the production segment there is a net savings of $20.7 million in nationwide annual costs.

Table 5-12 Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Options by Industry Segment

Industry Segment	Number of Sources subject to NSPS*	Capital Cost Per Device/IAS ($)**	Annual Costs ($/year)		Nationwide Emission Reductions (tpy)†			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs ($/year)		
			without savings	with savings	VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 1 (emission threshold equal to 0 scfh)														
Natural Gas Processing	15	16,972	11,090	7,606	63	225	2	2,656	1,822	738	506	254,576	166,351	114,094
Regulatory Option 2 (emission threshold equal to 6 scfh)														
Oil and Natural Gas Production	13,632	165	23	(1,519)	25,210	90,685	952	13	net savings	4	net savings	2,249,221	320,071	(20,699,918)
Natural Gas Transmission and Storage	67	165	23	23	6	212	0.2	262	262	7	7	11,039	1,539	1,539

Minor discrepancies may be due to rounding.

a. The number of sources subject to NSPS for the natural gas processing and the natural gas transmission and storage segments represent the number of new devices expected per year reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed devices can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments. For the natural gas processing segment the number of new sources represents the number of Instrument Air Systems (IAS) that is expected to be installed, with each IAS expected to power 15 control loops (or replace 15 pneumatic devices).

b. The capital cost for regulatory option 2 is equal to the incremental cost of a low bleed device versus a new high bleed device. The capital cost of the IAS is based on the small IAS as summarized in Table 5-10.

c. Nationwide emission reductions vary based on average expected emission rates of bleed devices typically used in each segment industry segment as summarized in Tables 5-2.

5.6 References

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6.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the air pollutant emissions from these compressors and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling pollutant emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

6.1 Process Description

6.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time,during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

6.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used to replace the wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic groves and springs. The opposing forcescreate a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are lower for dry seals in comparison to wet seals.

6.2 Emissions Data and Emission Factors

6.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 6-1, along with the type of information contained in the study.

6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study[1] and use the methane to pollutant ratios developed in the gas composition memorandum.[2] The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 6-2. Once the methane emissions were calculated, ratios were used to estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP). The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane and 0.105 pounds HAP per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane and 0.0008 pounds HAP per pound of methane for the transmission and storage segments. A summary of the reciprocating compressor emissions are presented in Table 6-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG inventory. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the

Table 6-1. Major Studies Reviewed for Consideration Of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[1]	EPA	2010	Nationwide	X	
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document[2]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[3]	Gas Research Institute/EPA	1996	Nationwide	X	
Natural Gas STAR Program[4,5]	EPA	1993-2010	Nationwide	X	X

Table 6-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor (% of hour/year Compressor Pressurized)	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)
Production (Well Pads)	0.271[a]	4	100%	N/A[f]	N/A[f]
Gathering & Boosting	25.9[b]	3.3	79.1%	N/A[f]	N/A[f]
Processing	57[c]	2.5	89.7%	47.7[g]	6[g]
Transmission	57[d]	3.3	79.1%	47.7[g]	6[g]
Storage	51[e]	4.5	67.5%	47.7[g]	6[g]

a. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-8.
b. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* (Draft): 2006.
c. EPA/GRI. (1996). Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Table 4-14.
d. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-17.
e. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-24.
f. The 1996 EPA/GRI Study Volume 11[3], does not report any centrifugal compressors in the production or gathering/boosting sectors, therefore no emission factor data were published for those two sectors.
g. U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks1990-2009. Washington, DC. April 2011. Annex 3. Page A-153.

Table 6-3.Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Baseline Emission Estimates (tons/year)		
	Methane	VOC	HAP
Reciprocating Compressors			
Production (Well Pads)	0.198	0.0549	0.00207
Gathering & Boosting	12.3	3.42	0.129
Processing	23.3	6.48	0.244
Transmission	27.1	0.751	0.0223
Storage	28.2	0.782	0.0232
Centrifugal Compressors (Wet seals)			
Processing	228	20.5	0.736
Transmission	126	3.50	0.104
Storage	126	3.50	0.104
Centrifugal Compressors (Dry seals)			
Processing	28.6	2.58	0.0926
Transmission	15.9	0.440	0.0131
Storage	15.9	0.440	0.0131

Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[4] A summary of the emission factors are presented in Table 6-2 and the individual compressor emission are shown in Table 6-3 for each of the oil and gas industry segments.

6.3 Nationwide Emissions from New Sources

6.3.1 Overview of Approach

The number of new affected facilities in each of the oil and gas sectors was estimated using data from the U.S. Greenhouse Gas Inventory,[5,6] with some exceptions. This basis was used whenever the total number of existing facilities was explicitly estimated as part of the Inventory, so that the difference between two years can be calculated to represent the number of new facilities. The Inventory was not used to estimate the new number of reciprocating compressor facilities in gas production, since more recent information is available in the comments received to subpart W of the mandatory reporting rule. Similarly, the Inventory was not used to estimate the new number of reciprocating compressor facilities in gas gathering, since more recent information is available in comments received as comments to subpart W of the mandatory reporting rule. For both gas production and gas gathering, information received as comments to subpart W of the mandatory reporting rule was combined with additional EPA estimates and assumptions to develop the estimates for the number of new affected facilities.

Nationwide emission estimates for new sources were then determined by multiplying the number of new sources for each oil and gas segment by the expected emissions per compressor using the emission data in Table 6-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and gas segments is presented in Table 6-4.

6.3.2 Activity Data for Reciprocating Compressors

6.3.2.1 Wellhead Reciprocating Compressors

The number of wellhead reciprocating compressors was estimated using data from industry comments on Subpart W of the Greenhouse Gas Mandatory Reporting Rule.[7] The 2010 U.S. GHG Inventory reciprocating compressor activity data was not considered in the analysis because it does not distinguish between wellhead and gathering and boosting compressors. Therefore, using data submitted to EPA during the subpart W comment period from nine basins supplied by the El Paso Corporation,[8] the

Table 6-4.Approximate Number of New Sources in the Oil and Gas Industry in 2008

Industry Segment	Number of New Reciprocating Compressors	Number of New Centrifugal Compressors
Wellheads	6,000	0
Gathering and Boosting	210	0
Processing	209	16
Transmission	20	14
Storage	4	

average number of new wellhead compressors per new well was calculated using the 315 well head compressors provided in the El Paso comments and 3,606 wells estimated in the Final Subpart W onshore production threshold analysis. This produced an average of 0.087 compressors per wellhead. The average wellhead compressors per well was multiplied by the total well completions (oil and gas) determined from the HPDI® database[9] between 2007 and 2008, which came to 68,000 new well completions. Using this methodology, the estimated number of new reciprocating compressors at production pads was calculated to be 6,000 for 2008. A summary of the number of new reciprocating compressors located at well pads is presented in Table 6-4.

6.3.2.2 Gathering and Boosting Reciprocating Compressors

The number of gathering & boosting reciprocating compressors was also estimated using data from industry comments on Subpart W. DCP Midstream stated on page 3 of its 2010 Subpart W comments that it operates 48 natural gas processing plants and treaters and 700 gathering system compressor stations. Using this data, there were an average of 14.583 gathering and boosting compressor stations per processing plant. The number of new gathering and boosting compressors was determined by taking the average difference between the number of processing plants for each year in the 2010 U.S Inventory, which references the total processing plants in the Oil and Gas Journal. This was done for each year up to 2008. An average was taken of only the years with an increase in processing plants, up to 2008. The resulting average was multiplied by the 14.583 ratio of gathering and boosting compressor stations to processing plants and the 1.5 gathering and boosting compressors per station yielding 210 new source gathering and boosting compressor stations and is shown in Table 6-4.

6.3.2.3 Processing Reciprocating Compressors

The number of new processing reciprocating compressors at processing facilities was estimated by averaging the increase of reciprocating compressors at processing plants in the greenhouse gas inventory data for 2007, 2008, and 2009.[10,11] The estimated number of existing reciprocating compressors in the processing segment was 4,458, 4,781, and 4,876 for the years 2007, 2008, and 2009 respectively. This calculated to be 323 new reciprocating compressors between 2007 and 2008, and 95 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 209 reciprocating compressors and was used to estimate the number of new sources in Table 6-4.

6.3.2.4 Transmission and Storage Reciprocating Compressors

The number of new transmission and storage reciprocating compressors was estimated using the differences in the greenhouse gas inventory[12,13] data for 2007, 2008, and 2009 and calculating an average of those differences. The estimated number of existing reciprocating compressors at transmission stations was 7,158, 7,028, and 7,197 for the years 2007, 2008, and 2009 respectively. This calculated to be -130 new reciprocating compressors between 2007 and 2008, and 169 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 20 reciprocating compressors and was used to estimate the number of new sources at transmission stations. The number of existing reciprocating compressors at storage stations was 1,144, 1,178, and 1,152 for the years 2007, 2008, and 2009 respectively. This calculated to be 34 new reciprocating compressors between 2007 and 2008, and -26 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 4 reciprocating compressors and was used to estimate the number of new sources at storage stations in Table 6-4.

6.3.3 Activity Data for Centrifugal Compressors

The number of new centrifugal compressors in 2008 for the processing and transmission/storage segments was determined by taking the average difference between the centrifugal compressor activity data for each year in the 2008 U.S. Inventory . For example, the number of compressors in 1992 was subtracted from the number of compressors in 1993 to determine the number of new centrifugal compressors in 1993. This was done for each year up to 2008. An average was taken of only the years with an increase in centrifugal compressors, up to 2008, to determine the number of new centrifugal compressors in 2008. The result was 16 and 14 new centrifugal compressors in the processing and transmission segments respectively. A summary of the estimates for new centrifugal compressor is presented in Table 6-4.

6.3.4 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 6-5 by industry segment.

Table 6-5.Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Nationwide baseline Emissions (tons/year)		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	1,186	330	12.4
Gathering & Boosting	2,587	719	27.1
Processing	4,871	1,354	51.0
Transmission	529	14.6	0.435
Storage	113	3.13	0.0929
Centrifugal Compressors			
Processing	3,640	329	11.8
Transmission/Storage	1,768	48.9	1.45

6.4 Control Techniques

6.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includesreplacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate optionfor reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[14] Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a flare. A summary of these techniques are presented in the following sections.

A control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a flare was considered to be a reasonable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. “Beam” type compressors have two seals, one on each end of the compressor, while “over-hung” compressors have a seal on only the “inboard” (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes “O-ring” rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the “inboard” (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a flare or other combustion device.

6.4.2 Reciprocating Compressor Rod Packing Replacement

6.4.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.

6.4.2.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions were calculated by comparing the average rod packing emissionswith the average emissions from newly installed and worn-in rod packing. Since the estimate for newly installed rod packing was intended for larger processing and transmission compressors, this analysis uses the estimate to calculate reductions from only gathering and boosting compressors and not wellhead compressor which are known to be smaller. The calculation for gathering and boosting reductions is shown in Equation 1.

$$R_{WP}^{G\&B} = \frac{Comp_{New}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6}$$ **Equation 1**

where,

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{G\&B}$ = Number of new gathering and boosting compressors;
$E_{G\&B}$ = Methane emission factor for gathering and boosting compressors inTable 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[15] for this analysis;
C = Average number of cylinders for gathering and boosting compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 79.1%;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

For wellhead reciprocating compressors, this analysis calculates a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The calculation for wellhead compressor reductions is shown in Equation 2 below.

$$R_{Well} = \frac{Comp_{New}^{Well}\left(E_{Well}\right) \times C \times O \times 8760}{10^6}\left(\frac{E_{Trans} - E_{New}}{E_{Trans}}\right)$$ **Equation 2**

where,

R_{Well} = Potential methane emission reductions from wellhead compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{Well}$ = Number of new wellhead compressors;
E_{Well} = Methane emission factor for wellhead compressors from Table 6-2, cubic feet per hour per cylinder;
C = Average number of cylinders for wellhead compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 100%;

E_{Trans} = Methane emissions factor for transmission compressors from Table 6-2 in cubic feet per hour per cylinder;
E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[16] for this analysis;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors in Table 6-2 by the average emission factor from newly installed rod packing. This calculation, shown in the Equation 3 below, was performed for each of the natural gas processing, transmission, and storage/LNG sectors.

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{\textit{Equation 3}}$$

where,

R_{PTS} = Potential methane emission reductions from processing, transmission, or storage compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{PTS}$ = Number of new processing, transmission, or storage compressors;
$E_{G\&B}$ = Methane emission factor for processing, transmission, or storage compressors in Table 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[17] for this analysis;
C = Average number of cylinders for processing, transmission, or storage compressors in Table 6-2;
O = Percent of time during the calendar year the average processing, transmission, or storage compressor is in the operating and standby pressurized modes, 89.7%, 79.1%, 67.5% respectively;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating rod packing replacement for each of the oil and gas segments is shown in Table 6-6. The emissions of VOC and HAP were calculated using the methane emission reductions calculated above the gas composition[18] for each of the segments. Reciprocating compressors in the processing sector were assumed to be used to compress production gas.

Table 6-6.Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Production (Well Pads)	6,000	0.158	0.0439	0.00165	947	263	9.91
Gathering & Boosting	210	6.84	1.90	0.0717	1,437	400	15.1
Processing	375	18.6	5.18	0.195	3,892	1,082	40.8
Transmission	199	21.7	0.600	0.0178	423	11.7	0.348
Storage	9	21.8	0.604	0.0179	87.3	2.42	0.0718

6.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas Star Lessons Learned document[19] which estimated the cost to replace the packing rings to be $1,620 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packingplacement is based on number of hours that the compressor operates. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. [20] The cost impacts arebased on the replacement of the rod packing 26,000 hours that the reciprocating compressor operates in the pressurized mode. The number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3 years for production compressors, 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors using the operating factors in Table 6-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3848, 0.3122, 0.3490, 0.3122, and 0.2720 for the production, gathering and boosting, processing, transmission, and storage sectors, respectively. The capital costs were calculated using the average rod packing cost of $1,620 and the average number of cylinders per segment in Table 6-2. The annual costs were calculated using the capital cost and the capital recovery factors. A summary of the capital and annual costs for each of the oil and gas segments is shown in Table 6-7.

Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[21] This cost was used to calculate theannual cost with gas savings using the methane emission reductions in Table 6-6. The annual cost with savings is shown in Table 6-7 for each of the oil and gas segments. The cost effectiveness for the reciprocating rod packing replacement option is presented in Table 6-7. There is no gas savings cost benefits for transmission and storage facilities, because they do not own the natural gas that is

Table 6-7. Cost Effectiveness for Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		Without savings	With savings	Without savings	With savings	Without savings	With savings
Production	$6,480	$2,493	$2,457	$56,847	$56,013	$15,802	$15,570
Gathering & Boosting	$5,346	$1,669	$83	$877	$43	$244	$12
Processing	$4,050	$1,413	-$2,903	$273	-$561	$76	-$156
Transmission	$5,346	$1,669	N/A	$2,782	N/A	$77	N/A
Storage	$7,290	$2,276	N/A	$3,766	N/A	$104	N/A

compressed at their compressor stations.

6.4.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no electricity maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packing

6.4.3 Centrifugal Compressor Dry Seals

6.4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of 6scfmmethane per compressor.[22] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[23,24]
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.

- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid “parasitic” equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

Centrifugal compressors were found in the processing and transmission sectors based on information in the greenhouse gas inventory.[25] Therefore, it was assumed that new compressors would be located in these sectors only.

6.4.3.2 Effectiveness

The control effectiveness of the dry seals was calculated by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 6-2 were used in combination with an operating factor of 43.6 percent for processing centrifugal compressors and 24.2 percent for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study.[26] The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.[27] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 6-8.

6.4.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between $50,000 and $100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3

Table 6-8. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)			Nationwide Emission Reductions (ton/year)		
		Methane	**VOC**	**HAP**	**Methane**	**VOC**	**HAP**
Transmission/Storage	16	199	18.0	0.643	3,183	287	10.3
Storage	14	110	3.06	0.0908	1,546	42.8	1.27

percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between \$2 million to \$5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is \$75,000. The annual cost was calculatedas the capital recovery of this capital cost assuming a 10-year equipment life and 7 percent interest which came to \$10,678 per compressor. The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is \$88,300 in comparison to wet seals. Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of \$4.00 per Mcf.[28] This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-8. A summary of the capital and annual costs for dry seals is presented in Table 6-9. The methane and VOC cost effectiveness for the dry seal option is also shown in Table 6-9. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station may not own the natural gas that is compressed at the station.

6.4.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

6.4.4 Centrifugal Compressor Wet Seals with a Flare

6.4.4.1 Description

Another control option used to reduce pollutant emissions from centrifugal compressors equipped withwet seals is to route the emissions to a combustion device or capture the emissions and route them to afuel system. A wet seal system uses oil that is circulated under high pressure between three rings aroundthe compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either

Table 6-9. Cost Effectiveness for Centrifugal Compressor Dry Seals

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-yr)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with O&M and gas savings	without savings	with O&M and gas savings	without savings	with O&M and gas savings
Processing	$75,000	$10,678	-$123,730	$595	-$6,892	$54	-$622
Transmission/Storage	$75,000	$10,678	-$77,622	$3,495	-$25,405	$97	-$703

combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

6.4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and HAP. A flare typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95 percent reduction of methane, VOC, and HAP. The wet seal emissions in Table 6-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 6-10.

6.4.4.3 Cost Impacts

The capital and annual cost of the enclosed flare was calculated using the methodology in the EPA Control Cost Manual.[29] The heat content of the gas stream was calculated using information from the gas composition memorandum.[30] A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 6-11. The methane and VOC cost effectiveness for the wet seals routed to a flare option is also shown in Table 6-12. There is no cost saving estimated for this option because the recovered gas is combusted.

6.4.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a flare. The combustion of the recovered gas creates secondary emissions of hydrocarbons, nitrogen oxide (NO_X), carbon dioxide (CO_2), and carbon monoxide (CO) emissions. A summary of the estimated secondary emission are presented in Table 6-11. No other wastes should be created or wastewater generated.

6.5 Regulatory Options

The affected facility definition for a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of thedriveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressor would be

Table 6-10. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Processing	16	216	19.5	0.699	3,283	296	10.6
Transmission/Storage	14	120	3.32	0.0986	1,596	44.2	1.31

Table 6-11. Secondary Impacts from Wet Seals Equipped with a Flare

Industry Segment	Secondary Impacts from Wet Seals Equipped with a Flare (tons/year)				
	Total Hydrocarbons	Carbon Monoxide	Carbon Dioxide	Nitrogen Oxides	Particulate Matter
Processing	0.0289	0.0205	7.33	0.00377	Negligible
Transmission/Storage	0.00960	0.00889	3.18	0.00163	Negligible

Table 6-12. Cost Effectiveness for Centrifugal Compressor Wet Seals Routed to a Flare

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with gas savings	without savings	with gas savings	without savings	with gas savings
Processing	$67,918	$103,371	N/A	$5,299	N/A	$478	N/A
Transmission/Storage	$67,918	$103,371	N/A	$31,133	N/A	$862	N/A

subject to a New Performance Standard (NSPS) at the time of installation. The following Regulatory options were evaluated:

- Regulatory Option 1: Require replacement of the reciprocating compressor rod packing based on26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2: Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3: Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

6.5.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 6.4.1. The VOC cost effectiveness from $56,847 for reciprocating compressors located at production pads to $273 for reciprocating compressors located at processing plants. The VOC cost effectiveness for the gathering and boosting, transmission, and storage segments were $877, $2,782, and 3,766 respectively. Based on these cost effectiveness values, Regulatory Option 1 was accepted for the processing, gathering and boosting, transmission, and storage segments and rejected for the production segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 6.4.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in comparison to wet seals. In addition, a vendor reported in 2003 that 90 percent of new compressors that were sold by the company were equipped with dry seals. Another vendor confirmed in 2010 that the rate at which new compressor sales have dry seals is still 90 percent; thus, it was assumed that from 2003 onward, 90 percent of new compressors are equipped with dry seals. The VOC cost effectiveness of dry seals was calculated to be $595 for centrifugal compressors located at processing plants, and $3,495 for centrifugal compressors located at transmission or storage facilities. Therefore, Regulatory Option 2 was accepted as a regulatory option for centrifugal compressors located at processing, transmission, or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a flare. Centrifugal compressors with wet seals are commonly used in high pressure applications over 3,000 pounds per square inch (psi). None of the applications in the oil and gas industry operate at these pressures. Therefore, it does not appear that any facilities would be required to operate a centrifugal compressor with wet seals. The VOC control effectiveness for the processing and transmission/storage segments were $5,299 and $31,133 respectively. Therefore, Regulatory Option 3 was rejected due to the high VOC cost effectiveness.

6.5.2 Nationwide Impacts of Regulatory Options

Tables 6-13 and 6-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 210 reciprocating compressors at gathering and boosting stations, 209 reciprocating compressors at processing plants, 20 reciprocating compressors at transmission facilities, and 4 reciprocating compressors at underground storage facilities. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-13.

Regulatory Option 2 is expected to affect 16 centrifugal compressors in the processing segment and 14 centrifugal compressors in the transmission and storage segments. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-14.

Table 6-13. Nationwide Cost Impacts for Regulatory Option 1

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions (tons/year)			Total Nationwide Costs		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost without savings ($/yr)	Annual Cost with savings ($/yr)
Gathering & Boosting	210	400	1,437	15.1	$1,122,660	$350,503	$17,337
Processing	209	1,082	3,892	40.8	$846,450	$295,397	-$606,763
Transmission	20	11.7	423	0.348	$104,247	$32,547	$32,547
Storage	4	2.42	87.3	0.0718	$29,160	$9,104	$9,104

Table 6-14. Nationwide Cost Impacts for Regulatory Option 2

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions[1] (tons/year)			Total Nationwide Costs[a]		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost w/o Savings ($/year)	Annual Cost w/ Savings ($/year)
Production (Well Pads)	0	0	0	0	0	0	0
Gathering & Boosting	0	0	0	0	0	0	0
Processing	16	118	422	4.42	$100,196	$14,266	-$120,144
Transmission/Storage	14	3.24	117	0.0962	$50,098	$7,133	-$37,017

a. The nationwide emission reduction and nationwide costs are based on the emission reductions and costs for 2 centrifugal compressors with wet seals located a processing facility and 1 centrifugal compressor equipped with wet seal located at a transmission or storage facility.

6.6 References

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7.0 STORAGE VESSELS

Storage vessels, or storage tanks, are sources of air emissions in the oil and natural gas sector. This chapter provides a description of the types of storage vessels present in the oil and gas sector, and provides emission estimates for a typical storage vessel as well as nationwide emission estimates. Control techniques employed to reduce emissions from storage vessels are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter provides a discussion of considerations used in developing regulatory alternatives for storage vessels.

7.1 Process Description

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, produced water, etc. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through as series of high-pressure and low-pressure separators. Crude oil under high pressure conditions is passed through either a two phase separator (where the associated gas is removed and any oil and water remain together) or a three phase separator (where the associated gas is removed and the oil and water are also separated). At the separator, low pressure gas is physically separated from the high pressure oil. The remaining low pressure oil is then directedto a storage vessel where it is stored for a period of time before being shipped off-site. The remaining hydrocarbons in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the remaining hydrocarbons from storage vessels are a function of working, breathing (or standing), and flash losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage vesselfrom a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vesselwill affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also includes ethane, butane, propane, and hazardous air pollutants (HAP) such as benzene, toluene, ethylbenzene, xylene (collectively referred to as BTEX), and n-hexane.

7.2 Emissions Data

7.2.1 Summary of Major Studies and Emissions

Given the potentially significant emissions from storage vessels, there have been numerous studies conducted to estimate these emissions. Many of these studies were consulted to evaluate the emissions and emission reduction options for emissions from storage vessels. Table 7-1 presents a summary of these studies, along with an indication of the type of information available in each study.

7.2.2 Representative Storage Vessel Emissions

Due to the variability in the sizes and throughputs, model tank batteries were developed to represent the ranges of sizes and population distribution of storage vessels located attank batteries throughout the sector. Model tank batteries were not intended to represent any single facility, but rather a range of facilities with similar characteristics that may be impacted by standards. Model tank batteries were developed for condensate tank batteries and crude oil tank batteries. Average VOC emissions were then developed and applied to the model tank batteries.

7.2.2.1 Model Condensate Tank Batteries

During the development of the national emissions standards for HAP (NESHAP) for oil and natural gas production facilities (40 CFR part 63, subpart HH), model plants were developed to represent condensate tank batteries across the industry.[1]For this current analysis, the most recent inventory data available was the 2008 U.S. Greenhouse Gas Emissions Inventory.[2,3] Therefore, 2008 was chosen to represent the base year for this impacts analysis.To estimate the current condensate battery population and distribution across the model plants, the number of tanks represented by the model plants was scaled

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emission Figures	Control Information
VOC Emissions from Oil and Condensate Storage Tanks[4]	Texas Environmental Research Consortium	2009	Regional	X	X
Lessons Learned from Natural Gas STAR Partners:Installing Vapor Recovery Units on Crude Oil Storage Tanks[5]	EPA	2003	National		X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report[6]	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economics Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number [7]	Colorado	2008	n/a		X
E&P TANKS[8]	American Petroleum Institute		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[2,3]	EPA	2008 and 2009	National	X	

from 1992 (the year for which that the model plants were developed under the NESHAP) to 2008 for this analysis. Based on this approach, it was estimated that there were a total of 59,286 existing condensate tanks in 2008. Condensate throughput data from the U.S. Greenhouse Gas Emissions Inventory was used to scale up from 1992 the condensate tank populations for each model condensate tank battery under the assumption that an increase in condensate production would be accompanied by a proportional increase in number of condensate tanks. The inventory data indicate that condensate production increased from a level of 106 million barrels per year (MMbbl/yr) in 1992to 124 MMbbl/yr in 2008.This increase in condensate production was then distributed across the model condensate tank batteriesin the same proportion as was done for the NESHAP. The model condensate tank batteries are presented in Table 7-2.

7.2.2.2 Model Crude Oil Tank Batteries

According to the Natural Gas STAR program,[5] there were 573,000 crude oil storage tanksin 2003. According to the U.S. Greenhouse Gas Emissions Inventory, crude oil production decreased from 1,464 MMbbl/yr in 2003 to 1,326 MMbbl/yr (a decrease of approximately 9.4 percent) in 2008. Therefore, it was assumed that the number of crude oil tanks in 2008 were approximately 90.6 percent of the number of tanks identified in 2003. Therefore, for this analysis it was assumed that there were 519,161 crude oil storage tanks in 2008. During the development of the NESHAP, model crude oil tank batteries were not developed and a crude oil tank population was not estimated. Therefore, it was assumed that the percentage distribution of crude oil storage tanks across the four model crude oil tank battery classifications was the same as for condensate tank batteries.Table 7-3 presents the model crude oil tank batteries.

7.2.2.3 VOC Emissions from Condensate and Crude Oil Storage Vessels

Once the modelcondensate and crude oil tank battery distributionswere developed, VOC emissions from a representative storage vessel were estimated. Emissions from storage vessels vary considerably depending on many factors, including, but not limited to, throughput, API gravity, Reid vapor pressure, separator pressure, etc. The American Petroleum Institute (API) has developed a software program called E&P TANKS which contains a dataset of more than 100 storage vessels from across the country.[8] A summary of the information contained in the dataset, as well as the output from the E&P TANKS program, is presented in Appendix A of this document. According to industry representatives, this

Table 7-2. Model Condensate Tank Batteries

	Model Condensate Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Condensate throughput (bbl/day)[a]	15	100	1,000	5,000
Condensate throughput (bbl/yr) [a]	5,475	36,500	365,000	1,825,000
Number of fixed-roof product storage vessels [a]				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Estimated tank battery population (1992)[a]	12,000	500	100	70
Estimated tank battery population (2008) [b]	14,038	585	117	82
Total number of storage vessels (2008) [b]	56,151	2,340	468	328
Percent of number of storage vessels in model condensate tank battery	94.7%	3.95%	0.789%	0.552%
Percent of throughput per model condensate tank battery[a]	26%	7%	15%	51%
Total tank battery condensate throughput (MMbbl/yr)[c]	32.8	9.11	18.2	63.8
Condensate throughput per model condensate battery (bbl/day)	6.41	42.7	427	2,135
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	106.8	534

Minor discrepancies may be due to rounding.

a. Developed for NESHAP (Reference 1).
b. Population of tank batteries for 2008 determined based on condensate throughput increase from 106 MMbbl/yr in 1992 to 124 MMbbl/yr in 2008 (References2,3).
c. 2008 condensate production rate of 124 MMbbl/yr distributed across model tank batteries using same relative ratio as developed for NESHAP (Reference 1).

Table 7-3. Model Crude Oil Tank Batteries

	Model Crude Oil Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Percent of number of condensate storage vessels in model size range[a]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[b]	491,707	20,488	4,098	2,868
Percent of throughput across condensate tank batteries	26%	7%	15%	51%
Crude oil throughput per model plant category (MMbbl/yr)	351	97.5	195	683
Crude oil throughput per storage vessel (bbl/day)	1.96	13.0	130	652

Minor discrepancies may be due to rounding.

a. Same relative percent of storage vessel population developed for model condensate tank batteries.Refer to Table 7-2.

b. Calculated by applying the percent of number of condensate storage vessels in model size range to total number of crude oil storage vessels (519,161 crude oil storage vessels estimated for 2008) (Reference 5).

c. Same relative percent of throughput developed for model condensate tank batteries.Refer to Table 7-2.

dataset in combination with the output of the E&P TANKS program is representative of the various VOC emissions from storage vessels across the country.[9]

The more than 100 storage vesselsprovided with the E&P TANKS program, which had varying characteristics, were modeled with a constant throughput (based on the assumption that emissions would increase in proportion with throughput) and the relationship of these different characteristics and emissionswas studied. While many of the characteristics impacted emissions, a correlation was found to exist between API gravity and emissions. The average API gravity for all storage vessels in the data set was approximately 40 degrees. Therefore, we selected an API gravity of 40 degrees as a parameter to distinguish between lower emitting storage vessels and higher emitting storage vessels.[i] While the liquid type was not specified for the storage vessels modeled in the study, it was assumed that condensate storage vessels would have higher emissions than crude oil storage vessels. Therefore, based on this study using the E&P TANKS program, it was assumed for this analysis that liquids with API gravity equal to or greater than 40 degrees should be classified as condensate and liquids with API gravity less than 40 degrees should be classified as crude oil.

The VOC emissions from all storage vessels in the analysis are presented in Appendix A.Table 7-4 presents a summary of the average VOC emissions from all storage vessels as well as the average VOC emissions from the storage vessels identified as being condensate storage vessels and those identified as being crude oil storage vessels. As shown in Table 7-4, the storage vessels were modeled at a constant throughput of 500 bpd.[ii]An average emission factor was developed for each type of liquid. The average of condensate storage vessel VOC emissions was modeled to be 1,046 tons/year or 11.5 lb VOC/bbl and the average of crude oil storage vessel VOC emissions was modeled to be 107 tons/year or 1.18 lb VOC/bbl. These emission factors were then applied to each of the two sets of model storage vessels in Tables 7-2 and 7-4 to develop the VOC emissions from the model tank batteries. These are presented in Table 7-5.

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[i] The range of VOC emissions within the 95 percent confidence interval for storage vessels with an API gravity greater than 40 degrees was from 667 tons/year to 1425 tons/year. The range for API gravity less than 40 degrees was 76 tons/year to 138.

[ii] This throughput was originally chosen for this analysis to be equal to the 500 bbl/day throughput cutoff in subpart HH. While not part of the analysis described in this document, one of the original objectives of the E&P TANKS analysis was to assess the level of emissions associated with a storage vessel with a throughput below this cutoff. Due to the assumption that emissions increase and decrease in proportion with throughput, it was decided that using a constant throughput of 500 bbl/day would still provide the information necessary to determine VOC emissions from model condensate and crude oil storage vessels for this document.

Table 7-4. Summary of Data from E&P TANKS Modeling

Parameter[a]		**Average of Dataset**	**Average of Storage Vessels with API Gravity > 40 degrees**	**Average of Storage Vessels with API Gravity ≤ 40 degrees**
Throughput Rate (bbl)		500	500	500
API Gravity		40.6	52.8	30.6
VOC	Emissions (tons/year)	531	1046	107
	Emission factor (lb/bbl)	5.8	11.5	1.18

a. Information from analysis of E&P Tanks dataset, refer to Appendix A.

Table 7-5. Model Storage Vessel VOC Emissions

Parameter	Model Tank Battery			
	E	**F**	**G**	**H**
Model Condensate Tank Batteries				
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	107	534
VOC Emissions (tons/year)[b]	3.35	22.3	223	1117
Model Crude Oil Tank Batteries				
Crude Oil throughput per storage vessel (bbl/day)[c]	2.0	13	130	652
VOC Emissions (tons/year)[d]	0.4	2.80	28	140

a. Condensate throughput per storage vessel from table 7-2.

b. Calculated using the VOC emission factor for condensate storage vessels of 11.5 lb VOC/bbl condensate.

c. Crude oil throughput per storage vessel from table 7-3.

d. Calculated using the VOC emission factor for crude oil storage vessels of 1.18 lb VOC/bbl crude oil.

7.3 Nationwide Baseline Emissions from New or Modified Sources

7.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of a federal rulemaking, referred to as the nationwide baseline emissions estimate. In order to develop the baseline emissions estimate, the number of new storage vessels expected in a typical year was calculated and then multiplied by the expected uncontrolled emissions per storage vessels presented in Table 7-5. In addition, to ensure no emission reduction credit was attributed to new sources that would already be required to be controlled under State regulations, it was necessary to account for the number of storage vessels already subject to State regulations as detailed below.

7.3.2 Number of New Storage Vessels Expected to be Constructed or Reconstructed

The number of new storage vessels expected to be constructed was determined for the year 2015 (the year of analysis for the regulatory impacts). To do this, it was assumed that the number of new or modified storage vessels would increase in proportion with increases in production. The Energy Information Administration (EIA), published crude oil production rates up to the year 2011.[10]Therefore, using the forecast function in Microsoft Excel® , crude oil production was predicted for the year 2015.[iii] From 2009 to 2015,[iv] the expected growth of crude oil production was projected to be 8.25 percent (from 5.36 bpd to 5.80 bpd). Applying this expected growth to the number of existing storage vessels results in an estimate of 4,890 new or modified condensate storage vessels and 42,811 new or modified crude oil storage vessels. The number of new or modified condensate and crude oil storage vessels expected to be constructed or reconstructed is presented in Table 7-6.

7.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it was first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed

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[iii] The crude oil production values published by the EIA include leased condensate. Therefore, the increase in crude oil production was assumed to be valid for both crude oil and condensate tanks for the purpose of this analysis.
[iv] For the purposes of estimating growth, the crude oil production rate in the year 2008 was considered an outlier for production and therefore was not used in this analysis.

Table 7-6. Nationwide Baseline Emissions for Storage Vessels

	Model Tank Battery				
	E	F	G	H	Total
Model Condensate Tank Batteries					
Total number of storage vessels (2008)	56,151	2,340	468	328	59,286
Total projected number of new or modified storage vessels (2015) [a]	4,630	193	39	27	4,889
Number of uncontrolled storage vessels in absence of federal regulation[b]	1,688	70	14	10	1,782
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	3.35	22.3	223	1,117	1,366
Total Nationwide Uncontrolled VOC Emissions	5,657	1,572	3,143	11,001	21,373
Model Crude Oil Tank Batteries					
Total number of storage vessels (2008)	491,707	20,488	4,098	2,868	519,161
Total projected number of new or modified storage vessels (2015) [a]	40,548	1,689	338	237	42,812
Number of uncontrolled storage vessels in absence of federal regulation[b]	14,782	616	123	86	15,607
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	0.4	2.80	28	140	171
Total Nationwide Uncontrolled VOC Emissions	6,200	1,722	3,444	12,055	23,421

Minor discrepancies may be due to rounding

a. Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.
b. Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.
c. VOC Emissions from individual storage vessel at model tank battery, see Table 7-5.

for sources already being controlled, it was necessary to determine which storage vessels were already being controlled. To do this, the 2005 National Emissions Inventory (NEI) was used.Storage vessels in the oil and natural gas sector were identified under the review of the maximum achievable control technology (MACT) standards.[11] There were 5,412 storage vessels identified in the NEI, and of these, 1,973 (or 36 percent) were identified as being uncontrolled. Therefore, this percent of storage vessels that would not require controls under State regulations was applied to the number of new or modified storage vessels results in an estimate of 1,782 new or modified condensate storage vessels and 15,607 new or modified crude oil storage vessels.These are also presented in Table 7-6.

7.3.4 Nationwide Emission Estimates for New or Modified Storage Vessels

Nationwide emissions estimates are presented in Table 7-6 for condensate storage vessels and crude oil storage vessels. Model storage vessel emissions were multiplied by the number of expected new or modified storage vessels that would be uncontrolled in the absence of a federal regulation.As shown in Table 7-6, the baseline nationwide emissions are estimated to be 21,373 tons/year for condensate storage vessels and 23,421 tons/year for crude oil storage vessels.

7.4 Control Techniques

7.4.1 Potential Control Techniques

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the storage vessels. The other option would be to route the emissions from the storage vessels to a combustor. These control technologies are described below along with their effectiveness as they apply to storage vessels in the oil and gas sector, cost impacts associated with the installation and operation of these control technologies, and any secondary impacts associated with their use.

7.4.2 Vapor Recovery Units

7.4.2.1 Description

Typically, with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are typically recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system. Vapors are then either sent to the pipeline for sale or used as on-site fuel.[5]

7.4.2.2 Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by approximately 95 percent.***Error! Bookmark not defined.***A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold.If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

7.4.2.3 Cost Impacts

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for proposed state-only revisions to a Colorado regulation.Cost information contained in the EIA was assumed to be giving in 2007 dollars.[7]Therefore costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a VRU was estimated to be $85,423 (escalated to 2008 dollars from $75,000 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $98,186. These cost data are presented in Table 7-7. Total annual costs were estimated to be $18,983/year.

7.4.2.4 Secondary Impacts

A VRU is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of a VRU.

Table 7-7. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Savings due to Fuel Sales ($/yr)	Annualized Total Cost ($/yr)[c]
VRU	$78,000					
Freight and Design		$1,500				
VRU Installation		$10,154				
Maintenance				$8,553		
Recovered natural gas					($1,063)	
Subtotal Costs (2007)	$78,000	$11,654		$8,553	($1,063)	
Subtotal Costs (2008)[d]	$85,423	$12,763	$98,186	$9,367	($1,164)	
Annualized costs (using 7% interest, 15 year equipment life)	$9,379	$1,401		n/a	n/a	$18,983

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

7.4.3 Combustors

7.4.3.1 Description and Effectiveness

Combustors are also used to control emissions from condensate and crude oil storage vessels.The type of combustor used is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[13] Combustors are used to control VOC in many industrial settings, since thecombustorcan normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[14] For this analysis, the types of combustors installed for the oil and gas sector are assumed to achieve 95 percent efficiency.[7] Combustors do not have the same operational issues as VRUs, however secondary impacts are associated with combustors as discussed below.

7.4.3.2 Cost Impacts

Cost data for a combustor was also obtained from the Initial EIA prepared for proposed state-only revisions to the Colorado regulation.[7] As performed for the VRU, costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a combustor, including an auto igniter and surveillance system was estimated to be $23,699 (escalated to 2008 dollars from $21,640 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $32,301. These cost data are presented in Table 7-8. Total annual costs were estimated to be $8,909/year.

7.4.3.3 Secondary Impacts

Combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates. Reliable data for emission factors from combustors on condensate and crude oil storage vessels are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.[13] These emissions factors, however, are thebest indication for secondary pollutants from combustors currently available. The secondary emissionsper storage vessel are provided in Table 7-9.

Table 7-8. Total Capital Investment and Total Annual Cost of a Combustor

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Annualized Total Cost ($/yr) [c]
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System[d]	$3,600				
Pilot Fuel				$1,897	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$4,897	
Subtotal Costs (2008) [e]	$23,699	$8,601	$32,301	$5,363	
Annualized costs (using 7% interest, 15 year equipment life)	$2,602	$944		n/a	$8,909

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
e. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

Table 7-9. Secondary Impacts for Combustors used to Control Condensate and Crude Oil Storage Vessels

Pollutant	Emission Factor	Units	Emissions per Storage Vessel (tons/year)[a]
THC	0.14	lb/MMBtu	0.0061
CO	0.37	lb/MMBtu	0.0160
CO_2	60	Kg/MMBtu[b]	5.62
NO_X	0.068	lb/MMBtu	2.95E-03
PM	40	µg/l (used lightly smoking flares due to criteria that flares should not have visible emissions i.e. should not smoke)	5.51E-05

a. Converted using average saturated gross heating value of the storage vessel vapor (1,968 Btu/scf) and an average vapor flow rate of 44.07 Mcf per storage vessel. See Appendix A.
b. CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

7.5 Regulatory Options and Nationwide Impacts of Regulatory Options

7.5.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid.Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a cutoff was evaluated to limit the applicability of the standards to these storage vessels. Rather than require a cutoff in terms of emissions that would require a facility to conduct an emissions test on their storage vessel, a throughput cutoff was evaluated. It was assumed that facilities would have storage vessel throughput data readily available. Therefore, we evaluated the costs of controlling storage vessels with varying throughputs to determine which throughput level would provide the most cost effective control option.

The standard would require an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustoris an option for tank batteries because of the operational issues associated with a VRU as discussed above.However the use of a VRU is preferable to a combustorbecause a combustordestroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor. Therefore, the cost impacts associated a VRU installed for the control of storage vessels were evaluated.

To conduct this evaluation, emission factor data from a study prepared for the Texas Environmental Research Consortium[15] was used to represent emissions from the different throughputs being evaluated. For condensate storage vessels, an emission factor of 33.3 lb VOC/bbl was used and for crude oil storage vessels, an emission factor of 1.6 lb VOC/bbl was used.Using the throughput for each control option, an equivalent emissions limit was determined.Table 7-10 presents the following regulatory options considered for condensate storage vessels:

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 0.5 bbl/day (equivalent emissions of 3.0 tons/year);

Table 7-10. Options for Throughput Cutoffs for Condensate Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	0.5	3.0	2.89	$18,983	$6,576	1782
2	1	6.1	5.77	$18,983	$3,288	94
3	2	12.2	11.55	$18,983	$1,644	94
4	5	30.4	28.87	$18,983	$658	24

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 33.3 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 2 bbl/day (equivalent emissions of 12 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 5.0 bbl/day (equivalent emissions of 30 tons/year);

As shown in Table 7-10, Regulatory Option 1 is not cost effective for condensate storage vessels with a throughput of 0.5 bbl/day.Therefore Regulatory Option 1 is rejected.Since the cost effectiveness associated with Regulatory Option 2 is acceptable ($3,288/ton), this option was selected. As shown in Table 7-5, Model Condensate Storage Vessel Categories F, G, and H have throughputs greater than 1 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels.

A similar evaluation was performed for crude oil vessels and is presented in Table 7-11 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 0.3 tons/year);
- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 5 bbl/day (equivalent emissions of 1.5 tons/year);
- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 20 bbl/day (equivalent emissions of 6 tons/year);
- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 50 bbl/day (equivalent emissions of 15 tons/year);

As shown in Table 7-11, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a throughput of 1 and 5 bbl/day, respectively. Therefore Regulatory Options 1 and 2 are rejected.Since the cost effectiveness associated with Regulatory Option 3 is acceptable ($3,422/ton), this option was selected. As shown in Table 7-5, Model Crude Oil Storage Vessel CategoriesG and H have throughputs greater than 20 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G

Table 7-11. Options for Throughput Cutoffs for Crude Oil Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	1	0.3	0.28	$18,983	$68,432	15607
2	5	1.5	1.4	$18,983	$13,686	825
3	20	5.8	5.55	$18,983	$3,422	209
4	50	14.6	13.87	$18,983	$1,369	209

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 1.6 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels.

7.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels.In addition, combined impacts for a typical storage vessel are presented.

7.5.3 Primary Environmental Impacts of Regulatory Options

Regulatory Option2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with an average throughput greater than 1 bbl/day.

- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with an average throughput greater than 20 bbl/day.

The number of storage vessels that would be subject to the regulatory options listed above are presented in Tables7-10 and 7-11. It was estimated that there would be 94 new or modified condensate storage vessels not otherwise subject to State regulationsand impacted by Regulatory Option 2 (condensate storage vessels).As shown in Table 7-11, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-12 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying 95 percent control efficiency to the VOC emissions presented in Table 7-6 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tons/year and 14,710 tons/year for Regulatory Option 3 (crude oil storage vessels).

Table 7-12. Nationwide Impacts of Regulatory Options

Model Tank Battery	Number of Sources subject to Regulatory Option[a]	VOC Emissions for a Typical Storage Vessel (tons/year)	Capital Cost forTypical Storage Vessel[b] ($)	Annual Cost for a Typical Storage Vessel[b] ($/yr)		Nationwide Emission Reductions (tons/year)[c]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
				without savings	with savings	VOC	Methane[d]	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2: Condensate Storage Vessels														
F	70	22.3	65,243	14,528	13,946	1,483	325	685	658	3129	3004	4.57	1.02	0.98
G	14	223	65,243	14,528	13,946	2,966	649	68	66	313	301	0.913	0.203	0.195
H	10	1117	65,243	14,528	13,946	10,612	2,322	14	13	62.6	60.1	0.652	0.145	0.139
Total for Regulatory Option 2						**15,061**	**3,296**					**6.14**	**1.37**	**1.31**
Regulatory Option 3: Crude Oil Storage Vessels														
G	123	28	65,243	14,528	13,946	3,272	716	546	524	2496	2396	8.02	1.79	1.71
H	86	140	65,243	14,528	13,946	11,438	2,503	109	104	499	479	5.61	1.25	1.20
Total for Regulatory Option 3						**14,710**	**3,219**					**13.6**	**3.04**	**2.91**
Combined Impacts[e]														
Typical Storage Vessel	**304**	**103**	**65,243**	**14,528**	**13,946**	**29,746**	**6,490**	**149**	**143**	**680**	**652**	**19.8**	**4.41**	**4.24**

Minor discrepancies may be due to rounding

a. Number of storage vessels in each model tank battery (refer to Table 7-6) determined to be subject to the regulatory option as outlined in Table 7-10.

b. It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU.This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-7 and 7-8.

c. Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.

d. Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A).Methane:VOC = 0.219

e. For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain the average VOC emissions per storage vessel.

7.5.4 Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Section 7.4. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be $65,243 (the average of the total capital investment for a VRU of $98,186 and $32,301 for a combustor from Tables 7-7 and 7-8, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be $14,528/yr (average of the total annual cost for a VRU of $20,147/yr and $8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) without including any cost savings due to fuel sales and $13,946/yr (average of the total annual cost for a VRU of $18,983/yr and $8,909/yr for a combustorfrom Tables 7-7 and 7-8, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-12, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be $6.14 million and for RegulatoryOption 3 (crude oil storage vessels) nationwide capital cost was estimated to be $13.6 million.Total annual costs without fuel savings were estimated to be $1.37 million/yr for Regulatory Option 2 (condensate storage vessels) and $3.04 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be $1.31 million/yr for Regulatory Option 2 (condensate storage vessels) and $2.91 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tons/year).Therefore, the nationwide annual costs were estimated to be $4.41 million/yr. A total nationwide VOC emission reduction of 29,746 tons/year results in a cost effectiveness of $149/ton.

7.5.5 Nationwide Secondary Emission Impacts

Regulatory Options 2 (condensate storage vessels) and 3 (crude oil storage vessels) allow for the use of a combustor; therefore the estimated nationwide secondary impacts are a result of combusting 50 percent of all storage vessel emissions. The secondary impacts for controlling a single storage vessel using a combustor are presented in Table 7-9. Nationwide secondary impacts are calculated by

Table 7-13. Nationwide Secondary Combined Impacts for Storage Vessels

Pollutant	Emissions per Storage Vessel (tons/year) [a]	Nationwide Emissions (tons/year)[b]
THC	0.0061	0.927
CO	0.0160	2.43
CO_2	5.62	854
NO_X	2.95E-03	0.448
PM	5.51E-05	0.0084

a. Emissions per storage vessel presented in Table 7-9.

b. Nationwide emissions calculated by assuming that 50 percent of the 304 impacted storage vessels would install a combustor.

multiplying 50 percent of the estimated number of impacted storage vessels (152) by the secondary emissions and are presented in Table 7-13.

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8.0 EQUIPMENT LEAKS

Leaks from components in the oil and natural gas sector are a source of pollutant emissions. This chapter explains the causes for these leaks, and provides emission estimates for "model" facilities in the various segments of the oil and gas sector. In addition, nationwide equipment leak emission estimates from new sources are estimated. Programs that are designed to reduce equipment leak emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for equipment leaks.

8.1 Equipment Leak Description

There are several potential sources of equipment leak emissions throughout the oil and natural gas sector. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following sub-sections describe potential equipment leak sources and the magnitude of the volatile emissions from typical facilities in the oil and gas industry.

Due to the large number of valves, pumps, and other components within oil and natural gas production, processing, and/or transmission facilities, total equipment leak VOC emissions from these components can be significant. Tank batteries or production pads are generally small facilities as compared with other oil and gas operations, and are generally characterized by a small number of components. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components.

8.2. Equipment leak Emission Data and Emissions Factors

8.2.1 Summary of Major Studies and Emission Factors

Emissions data from equipment leaks have been collected from chemical manufacturing and petroleum production to develop control strategies for reducing HAP and VOC emissions from these sources.[1,2,3] In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies were consulted. Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

8.2.2 Model Plants

Facilities in the oil and gas sector can consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where "surface sites" can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to equipment counts was obtained from a natural gas industry report. This document provided average equipment counts for gas production, gas processing, natural gas transmission and distribution. These average counts were used to develop model plants for wellheads, well pads, and gathering line and boosting stations in the production segment of the industry, for a natural gas processing plant, and for a compression/transmission station in the natural gas transmission segment. These equipment counts are consistent with those contained in EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), These model plants are discussed in the following sections.

8.2.2.1 Oil and Natural Gas Production

Oil and natural gas production varies from site-to site. Many production sites may include only a wellhead that is extracting oil or natural gas from the ground. Other production sites consist of wellheads attached to a well pad. A well pad is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) associated with these operations. A well pad can serve one well on a pad or several wells on a pad. A wellhead site consisting of only the wellhead and affiliated piping is not considered to be a well pad. The number of wells feeding into a well pad can vary from one to as many as 7 wells. Therefore, the number of components with potential for equipment leaks can vary depending on the number of wells feeding into the production pad and the amount of processing equipment located at the site.

Table 8-1. Major Studies Reviewed for Consideration or Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor (s)	Emissions Data	Control Options
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents	EPA	2010	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[4]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[567]	Gas Research Institute / EPA	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [8]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [9]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [10]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [11]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[12]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [13]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities [14]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[15]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [16]	EPA	1999		X	X
Protocol for Equipment Leak Emission Estimates[17]	EPA	1995	Nationwide	X	X

In addition to wellheads and well pads, model plants were developed for gathering lines and boosting stations. The gathering lines and boosting stations are sites that collect oil and gas from well pads and direct them to the gas processing plants. These stations have similar equipment to well pads; however they are not directly connected to the wellheads.

The EPA/GRI report provided the average number of equipment located at a well pad and the average number of components for each of these pieces of equipment.[4]The type of production equipment located at a well pad include: gas wellheads, separators, meters/piping, gathering compressors, heaters, and dehydrators. The types of components that are associated with this equipment include: valves, connectors, open-ended lines, and pressure relief valves. Four model plants were developed for well pads and are presented in Table 8-2. These model plants were developed starting with one, three, five and seven wellheads, and adding the average numberof other pieces of equipment per wellhead. Gathering compressors are not included at well pads and were included in the equipment for gathering lines and boosting stations.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. for the EPA/GRI document. A summary of the component counts for oil and gas production well pads is presented in Table 8-3.

Gathering line and boosting station model plants were developed using the average equipment counts for oil and gas production. The average equipment count was assigned Model Plant 2 and Model Plants 1 and 3 were assumed to be equally distributed on either side of the average equipment count. Therefore, Model Plant 1 can be assumed to be a small gathering and boosting station, and Model Plant 3 can be assumed to be a large gathering and boosting station. A summary of the model plant production equipment counts for gathering lines and boosting stations is provided in Table 8-4.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. from the EPA/GRIdocument. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in a Chapter 6 of this document. A summary of the component counts for oil and gas gathering line and boosting stations are presented in Table 8-5.

Table 8-2.Average Equipment Count for Oil and Gas Production Well Pad Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Gas Wellheads	1	5	48
Separators	---	4	40
Meter/Piping	---	2	24
In-Line Heaters	---	2	26
Dehydrators	---	2	19

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-3.Average Component Count for Oil and Gas Production Well Pad Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3	Model Plant 4
Valve	9	122	235	348
Connectors	37	450	863	1,276
Open-Ended Line	1	15	29	43
Pressure Relief Valve	0	5	10	15

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-4.Average Equipment Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Separators	7	11	15
Meter/Piping	4	7	10
Gathering Compressors	3	5	7
In-Line Heaters	4	7	10
Dehydrators	3	5	7

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-5. Average Component Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3
Valve	547	906	1,265
Connectors	1,723	2,864	4,005
Open-Ended Line	51	83	115
Pressure Relief Valve	29	48	67

DataSource: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8:Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

8.2.2.2 Oil and Natural Gas Processing

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the gas from the processing facility to the transmission stations.

New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, subpart KKK), and were assumed to be the baseline emissions for this analysis. Only one model plant was developed for the processing sector. A summary of the model plant production components counts for an oil and gas processing facility is provided in Table 8-6.

8.2.2.3 Natural Gas Transmission/Storage

Natural gas transmission/storage stations are facilities that use compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include emissions from gathering lines and boosting stations. Component counts were obtained from the EPA/GRI report and are presented in Table 8-7.

8.3 Nationwide Emissions from New Sources

8.3.1 Overview of Approach

Nationwide emissions were calculated by using the model plant approach for estimating emissions. Baseline model plant emissions for the natural gas production, processing, and transmission sectors were calculated using the component counts and the component gas service emission factors.[5]Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors for the production and processing sectors that were used to estimate the new source emissions are presented in Table 8-8. Emission factors for the transmission sector are presented in

Table 8-6.Average Component Count for Oil and Gas Processing Model Plant

Component	Gas Plant (non-compressor components)
Valve	1,392
Connectors	4,392
Open-Ended Line	134
Pressure Relief Valve	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

Table 8-7.Average Component Count for a Gas TransmissionFacility

Component	Processing Plant Component Count
Valve	704
Connection	3,068
Open-Ended Line	55
Pressure Relief Valve	14

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-16, June 1996. (EPA-600/R-96-080h)

Table 8-8 Oil and Gas Production and Processing Operations Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	4.5E-03
Connectors	Gas	2.0E-04
Open-Ended Line	Gas	2.0E-03
Pressure Relief Valve	Gas	8.8E-03

Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

Table 8-9. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions.[6] A summary of the baseline emissions for each of the sectors are presented in Table 8-10.

8.3.2 Activity Data

Data from oil and gas technical documents and inventories were used to estimate the number of new sources for each of the oil and gas sectors. Information from the Energy Information Administration (EIA) was used to estimate the number of new wells, well pads, and gathering and boosting stations. The number of processing plants and transmission/storage facilities was estimated using data from the Oil and Gas Journal, and the EPA Greenhouse Gas Inventory. A summary of the steps used to estimate the new sources for each of the oil and gas sectors is presented in the following sections.

8.3.2.1 Well Pads

The EIA provided a forecast of the number of new conventional and unconventional gas wells for the Year 2015 for both exploratory and developmental wells. The EIA projected 19,097 conventional and unconventional gas wells in 2015. The number of wells was converted to number of well pads by dividing the total number of wells by the average number of wells serving a well pad which is estimated to be 5. Therefore, the number of new well pads was estimated to be 3,820. The facilities were divided into the model plants assuming a normal distribution of facilities around the average model plant (Model Plant 2).

8.3.2.2 Gathering and Boosting

The number of new gathering and boosting stations was estimated using the current inventory of gathering compressors listed in the EPA Greenhouse Gas Inventory. The total number of gathering compressors was listed as 32,233 in the inventory. The GRI/EPA document does not include a separate list of compressor counts for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the inventory of 32,233 compressors and the average number of 4.5 compressors per facility, we estimated the number of gathering and boosting stations to be 7,163. To estimate the number of new gathering and boosting stations, we used the same increase of 3.84 percent used to estimate well pads to estimate the number of new gathering and boosting stations. This provided an estimate of 275 new gathering and boosting

Table 8-9 Oil and Gas Transmission/Storage Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	5.5E-03
Connectors	Gas	9.3E-04
Open-Ended Line	Gas	7.1E-02
Pressure Relief Valve	Gas	3.98E-02

Data Source:EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17, June 1996. (EPA-600/R-96-080h)

Table 8-10. Baseline Emissions for the Oil and Gas Production, Processing, and Transmission/Storage Model Plants

Oil and Gas Sector	Model Plant	TOC Emissions (Tons/yr)	Methane Emissions (Tons/yr)	VOC Emissions (Tons/yr)	HAP Emissions (Tons/yr)
Well Pads	1	0.482	0.335	0.0930	0.00351
	2	13.3	9.24	2.56	0.0967
	3	139	96.5	26.8	1.01
Gathering & Boosting	1	30.5	21.2	5.90	0.222
	2	50.6	35.2	9.76	0.368
	3	70.6	49.1	13.6	0.514
Processing	1	74.0	51.4	14.3	0.539
Transmission/Storage	1	108.1	98.1	2.71	0.0806

stations that would be affected sources under the proposed NSPS. The new gathering and boosting stations were assumed to be normally distributed around the average model plant (Model Plant 2).

8.3.2.3 Processing Facilities

The number of new processing facilities was estimated using gas processing data from the Oil and Gas Journal. The Oil and Gas Journal Construction Survey currently shows 6,303 million cubic feet of gas per day (MMcf/day) additional gas processing capacity in various stages of development. The OGJ Gas Processing Survey shows that there is 26.9 trillion cubic feet per year (tcf/year) in existing capacity, with a current throughput of 16.6 tcf/year or 62 percent utilization rate. If the utilization rate remains constant, the new construction would add approximately 1.4 tcf/year to the processing system. This would be an increase of 8.5 percent to the processing sector. The recent energy outlook published by the EIApredicts a 1.03 tcf/year increase in natural gas processing from 21.07 to22.104 tcf/year. This would be an annual increase of 5 percent over the next five years.

The EPA Greenhouse Gas Inventory estimates the number of existing processing facilities to be 577 plants operating in the U.S. Based on the projections provided in Oil and Gas Journal and EIA, it was assumed that the processing sector would increase by 5 percent annually. Therefore the number of new sources was estimated to be 29 new processing facilities in the U.S.

8.3.2.4 Transmission/Storage Facilities

The number of new transmission and storage facilities was estimated using the annual growth rate of 5 percent used for the processing sector and the estimated number of existing transmission and storage facilities in the EPA Greenhouse Inventory. The inventory estimates 1,748 transmission stations and 400 storage facilities for a total of 2,148. Therefore, the number of new transmission/storage facilities was estimated to be 107.

8.3.3 Emission Estimates

Nationwide emission estimates for the new sources for well pads, gathering and boosting, processing, and transmission/storage are summarized in Table 8-11. For well pads and gathering and boosting stations, the numbers of new facilities were assumed to be normally distributed across the range of model plants.

Table 8-11. Nationwide Baseline Emissions for New Sources

Oil and Gas Sector	Model Plant	Number of New Facilities	TOC Emissions (tons/yr)	Methane Emissions (tons/yr)	VOC Emissions (tons/yr)	HAP Emissions (tons/yr)
Well Pads	1	605	292	203	56.3	2.12
	2	2,610	34,687	24,116	6,682	252
	3	605	84,035	58,389	16,214	612
	Total	3,820	119,014	82,708	22,952	866
Gathering & Boosting	1	44	1,312	912	254	9.55
	2	187	9,513	6,618	1,835	69.2
	3	44	3,106	2,160	598	22.6
	Total	275	13,931	9,690	2,687	101
Processing	1	29	2,146	1,490	415	15.6
Transmission/Storage	1	107	11,567	10,497	290	8.62

8.4 Control Techniques

8.4.1 Potential Control Techniques

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are a significant source of VOC and HAP emissions from oil and gas facilities. The following section describes the techniques used to reduce emissions from these sources.

The most effective control technique for equipment leaks is the implementation of a leak detection and repair program (LDAR). Emissions reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The elements of an effective LDAR program include:

- Identifying Components;
- Leak Definition;
- Monitoring Components;
- Repairing Components; and
- Recordkeeping.

The primary source of equipment leak emissions from oil and gas facilities are from valves and connectors, because these are the most prevalent components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Most NSPS regulations have a leak definition of 10,000 ppm, while many NESHAP regulations use a 500-ppm or 1,000-ppm leak definition. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using toxic vapor analyzer (TVA) or organic vapor analyzer (OVA). In addition, other monitoring tools such as; infrared camera, soap solution, acoustic leak detection, and electronic screening device, can be used to monitor process components.

In optical gas imaging, a live video image is produced by illuminating the view area with laser light in the infrared frequency range. In this range, hydrocarbons absorb the infrared light and are revealed as a dark image or cloud on the camera. The passive infrared cameras scan an area to produce images of equipment leaks from a number of sources. Active infrared cameras point or aim an infrared beam at a potential source to indicate the presence of equipment leaks. The optical imaging camera is easy to use and very efficient in monitoring many components in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of equipment leak. To quantify the leak, the user would need to measure the concentration of the leak using a TVA or OVA. In addition, the optical imaging camera has a high upfront capital cost of purchasing the camera.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are measured separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 1, 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type. Also, many LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals. For each component that is found to be leaking, the first attempt at repair is to be made no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- Tightening of bonnet bolts;

- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Once the component is repaired; it should be monitored daily over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair component is to replace the leaking component with “leakless” or other technologies.

The LDAR recordkeeping requirement for each regulated process requires that a list of all ID numbers be maintained for all equipment subject to an equipment leak regulation. A list of components that are designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring, which may include leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

Other factors that can improve the efficiency of an LDAR program that are not addressed by the standards include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

The first LDAR option is the implementation of a subpart VVa LDAR program. This program is similar to the VV monitoring, but finds more leaks due to the lower leak definition, thereby achieving better emission reductions. The VVa LDAR program requires the annual monitoring of connectors using an OVA or TVA (10,000 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (500 ppm leak definition). The monitoring of each of the equipment types were also analyzed as a possible option for reducing equipment leak emissions. The second option involves using the monitoring requirements in subpart VVa for each type of equipment which include: valves; connectors; pressure relief devices; and open-ended lines for each of the oil and gas sectors.

The thirdoption that was investigated was the implementation of a LDAR program using an optical gas imaging system. This option is currently available as an alternative work practice (40 CFR Part 60, subpart A) for monitoring emissions from equipment leaks in subpart VVa. The alternative work practice requires monthly monitoring of all components using the optical gas imaging system and an annual monitoring of all components using a Method 21 monitoring device. The Method 21 monitoring allows the facility to quantify emissions from equipment leaks, since the optical gas imaging system can only provide the magnitude of the equipment leaks.

A fourth option that was investigated is a modification of the 40 CFR Part 60, subpart Aalternative work practice. The alternative work practice was modified by removing the required annual monitoring using a Method 21 instrument. This option only requires the monthly monitoring of components using the optical gas imaging system.

8.4.2 Subpart VVa LDAR Program

8.4.2.1 Description

The subpart VVa LDAR requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measure the concentration of the organics if the component is leaking. Connectors, valves, and pressure relief devices have a leak definition of 500 parts per million by volume (ppmv). Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves have no monitoring requirements, but are required to operate without any detectable emissions. Compressors are not included in this LDAR option and are regulated separately.

8.4.2.2 Effectiveness

The control effectiveness of the LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. A summary of the chemical manufacturing and petroleum refinery control effectiveness for each of the components is shown in Table 8-12. As shown in the table the control effectiveness for all of the components varies from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition. Descriptions of the frequency of monitoring and leak definition are described further below.

> Monitoring Frequency: The monitoring frequency is the number of times each component is checked for leaks. For an example, quarterly monitoring requires that each component be checked for leaks 4 times per year, and annual monitoring requires that each component be checked for leaks once per year. As shown in Table 8-12, monthly monitoring provides higher control effectiveness than quarterly

Table 8-12. Control Effectiveness for an LDAR program at a Chemical Process Unit and a Petroleum Refinery

Equipment Type and Service	Control Effectiveness (% Reduction)		
	Monthly Monitoring 10,000 ppmv Leak Definition	Quarterly Monitoring 10,000 ppmv Leak Definition	500 ppm Leak Definition[a]
Chemical Process Unit			
Valves – Gas Service[b]	87	67	92
Valves – Light Liquid Service[c]	84	61	88
Pumps – Light Liquid Service[c]	69	45	75
Connectors – All Services	---	---	93
Petroleum Refinery			
Valves – Gas Service[b]	88	70	96
Valves – Light Liquid Service[c]	76	61	95
Pumps – Light Liquid Service[c]	68	45	88
Connectors – All Services	---	---	81

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

a. Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.

b. Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.

c. Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

monitoring. This is because leaking components are found and repaired more quickly, which lowers the amount of emissions that are leaked to the atmosphere.

> Leak Definition: The leak definition describes the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound. Decreasing the leak definition concentration generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The control effectiveness for the well pad, gathering and boosting stations, processing facilities, and transmissions and storage facilities were calculated using the LDAR control effectiveness and leak fraction equations for oil and gas production operation units in the EPA equipment leaks protocol document. The leak fraction equation uses the average leak rate (e.g., the component emission factor) and leak definition to calculate the leak fraction.[7] This leak fraction is used in a steady state set of equations to determine the final leak rate after implementing a LDAR program.[8] The initial leak rate and the final leak rate after implementing a LDAR program were then used to calculate the control effectiveness of the program. The control effectiveness for implementing a subpart VVa LDAR program was calculated to be 93.6 perccent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.2.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Subpart VVa monitoring frequency and leak definition were used for processing plants since they are already required to do subpart VV requirements. Connectors were assumed to be monitored over a 4-year period after initial annual compliance monitoring.
- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that it takes approximately 1 minute to monitor a single component, and approximately 451 components would have to be monitored at an average facility in a month. This calculates to be 451 minutes or 7.5 hours per day. Assuming 20 working days in a typical month, a single Method 21 device could monitor 20 facilities. Therefore, the capital cost of the Method 21 device ($6,500) was divided by 20 to get a shared capital cost of $325 per facility. It was assumed for processing facilities that the full cost of the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated using assuming the same 1 minute per component monitoring time. The average number of components that would need to be monitored in a month was estimated to be 1,440, which calculates to be 24 hours of monitoring time or 3 days. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single Method 21 device is 7. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $929 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors are provided in Table 8-13. In addition to the full subpart VVa LDAR monitoring, a component by component LDAR analysis was performed for each of the oil and gas sectors using the component count for an average size facility. This Model Plant 2 for well pads, Model Plant 2 for gathering and boosting stations, and Model Plant 1 for processing plants and transmission and storage facilities.

Table 8-13. Summary of the Model Plant Cost Effectiveness for the Subpart VVa Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,418	$23,423	$23,350	$267,386	$7,088,667	$74,253
2	2.43	0.0915	8.73	$69,179	$37,711	$35,687	$15,549	$412,226	$4,318
3	25.3	0.956	91.3	$584,763	$175,753	$154,595	$6,934	$183,835	$1,926
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$148,885	$57,575	$52,921	$10,327	$273,769	$2,868
2	9.23	0.348	33.2	$255,344	$84,966	$77,259	$9,203	$243,987	$2,556
3	12.9	0.486	46.4	$321,203	$105,350	$94,591	$8,174	$216,692	$2,270
Processing Plants									
1	13.5	0.508	48.5	$7,522	$45,160	$33,915	$3,352	$88,870	$931
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$94,482	$51,875	N/A	$19,769	$665,155	$546

Note: Transmission and storage facilities do not own the natural gas; therefore they do not receive any cost benefits from reducing the amount of natural gas as the result of equipment leaks.

The component costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.
- Administrative costs and initial planning and training costs are were included for the component option and are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be $6,500.

The component control effectiveness for the subpart VVa component option were 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. These were the same control effectiveness’s that were used for the subpart VVa facility option. The control effectiveness for the modified subpart VVa option with less frequent monitoring was estimated assuming the control effectiveness follows a hyperbolic curve or a 1/x relationship with the monitoring frequency. Using this assumption the component cost effectiveness’s were determined to be 87.2 percent for valves, 81.0 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. The assumption is believed to provide a conservative estimate of the control efficiency based on less frequent monitoring. A summary of the capital and annual costs and the cost effectiveness for each of the components for each of the oil and gas sectors are provided in Tables 8-14, 8-15, 8-16, and 8-17.

8.4.2.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

Table 8-14. Summary of Component Cost Effectiveness for Well Pads for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	235	12	1.84	0.0696	6.64	$11,175	$27,786	$15,063	$399,331	$4,183
Connectors	863	1/0.25[a]	0.308	0.0116	1.11	$7,830	$22,915	$74,283	$1,969,328	$20,628
PRD	10	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870
Modified Subpart VVa– Less Frequent Monitoring										
Valves	235	1	1.31	0.0496	4.73	$11,175	$23,436	$17,828	$472,640	$4,951
Connectors	863	1/0.125[b]	0.261	0.00983	0.938	$7,830	$22,740	$87,277	$2,313,795	$24,237
PRD	5	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-15. Summary of Component Cost Effectiveness for Gathering and Boosting Stations for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	906	12	7.11	0.268	25.6	$24,524	$43,234	$6,079	$161,162	$1,688
Connectors	2,864	1/0.25[a]	1.02	0.0386	3.69	$10,914	$24,164	$23,603	$625,752	$6,555
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469
Modified Subpart VVa – Less Frequent Monitoring										
Valves	906	1	5.07	0.191	18.2	$24,524	$24,461	$5,221	$138,417	$1,450
Connectors	2,864	1/0.125[b]	0.865	0.0326	3.11	$10,914	$23,584	$27,274	$723,067	$7,574
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-16. Summary of Incremental Component Cost Effectiveness for Processing Plants for the Subpart VVa Option

Component	**Average Number of Components**	**Monitoring Frequency (Times/yr)**	**Annual Emission Reductions (tons/year)**			**Capital Cost ($)**	**Annual Cost ($/yr)**	**Cost-effectiveness ($/ton)**		
			VOC	**HAP**	**Methane**			**VOC**	**HAP**	**Methane**
Incremental Component Cost for Subpart VV to Subpart VVa Option										
Valves	1,392	12	10.9	0.412	39.3	$6,680	$1,576	$144	$3,824	$40
Connectors	4,392	1/0.25[a]	1.57	0.0592	5.65	$2,559	$6,845	$4,360	$115,585	$1,211
PRD	29	0	0.499	0.0188	1.80	$0	$0	$0	$0	$0
OEL	134	0	0.476	0.0179	1.71	$0	$0	$0	$0	$0

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

Table 8-17. Summary of Component Cost Effectiveness for Transmission and Storage Facilities for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	673	12	0.878	0.0261	31.8	$19,888	$37,870	$43,111	$1,450,510	$1,192
Connectors	3,068	1/0.25[a]	0.665	0.0198	24.1	$11,229	$24,291	$36,527	$1,229,005	$1,010
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684
Modified Subpart VVa – Less Frequent Monitoring										
Valves	673	1	0.626	0.0186	22.6	$19,888	$25,410	$40,593	$1,365,801	$1,122
Connectors	3,068	1/0.125[b]	0.562	0.0167	20.3	$11,229	$23,669	$42,140	$1,417,844	$1,165
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

8.4.3 LDAR with Optical Gas Imaging

8.4.3.1 Description

The alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components. This LDAR requires monthly monitoring and repair of components using an optical gas imaging system, and annual monitoring of components using a Method 21 instrument. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and arediscussed in Chapter 6 of this document.

8.4.3.2 Effectiveness

No data was found on the control effectiveness of the alternative work practice. It is believed that this option would provide the same control effectiveness as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.3.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- Annual monitoring costs using a Method 21 device are estimated to be $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single optical gas imaging and a Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the optical gas imaging system and the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that 8 production pads could be monitored per day. This means that 160 production facilities could be monitored in a month. In addition, it was assumed 13 gathering and boosting station would service these wells and could be monitored during the same month for a total of 173 facilities. Therefore, the capital cost of the optical gas imaging system (Flir Model GF320, $85,000) and the Method 21 device ($6,500) was divided by 173 to get a shared capital cost of $529 per facility. It was assumed for processing facilities that the full cost of the optical gas imaging system and the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated assuming that one facility could be monitored in one hour, and the travel time between facilities was one hour. Therefore, in a typical day 4 transmission stations could be monitored in one day. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single optical gas imaging system and Method 21 device is 80. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $1,144 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectorusing the alternative work practice monitoring is provided in Table 8-18. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.3.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of

Table 8-18. Summary of the Model Plant Cost Effectiveness for the Optical Gas Imaging and Method 21 Monitoring Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,428	$21,464	$21,391	$245,024	$6,495,835	$68,043
2	2.43	0.0915	8.73	$64,858	$39,112	$37,088	$16,127	$427,540	$4,478
3	25.3	0.956	91.3	$132,891	$135,964	$114,807	$5,364	$142,216	$1,490
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$149,089	$63,949	$59,295	$11,470	$304,078	$3,185
2	9.23	0.348	33.2	$240,529	$93,210	$85,503	$10,096	$267,659	$2,804
3	12.9	0.486	46.4	$329,725	$121,820	$111,060	$9,451	$250,567	$2,625
Processing Plants									
1	13.5	0.508	48.5	$92,522	$87,059	$75,813	$6,462	$171,321	$1,795
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$20,898	$51,753	N/A	$19,723	$663,591	$545

Minor discrepancies may be due to rounding.

Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission segment..

equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.4.4 Modified Alternative Work Practice with Optical Gas Imaging

8.4.4.1 Description

The modified alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components, but removes the requirement of the annual Method 21 device monitoring. Therefore, the modified work practice would require only monthly monitoring and repair of components using an optical gas imaging system. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are regulated separately.

8.4.4.2 Effectiveness

No data was found on the control effectiveness of this modified alternative work practice. However, it is believed that this option would provide the similar control effectiveness and emission reductions as the subpart VVa monitoring program. Therefore, the control effectiveness’s for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.4.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are \$17.70 for valves, \$1.13 per connector, \$78.00 for pressure relief valve disks, \$3,852 for pressure relief valve disk holder and valves, and \$102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be \$0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- A wage rate of \$30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The shared capital cost for optical gas imaging system is $491 for production and gathering and boosting, $85,000 for processing, and $1,063 for transmission for a FLIR Model GF320 optical gas imaging system.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors using the alternative work practice monitoring is provided in Table 8-19. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.4.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.5 Regulatory Options

The LDAR pollution prevention approach is believed to be the best method for reducing pollutant emissions from equipment leaks. Therefore, the following regulatory options were considered for reducing equipment leaks from well pads, gathering and boosting stations, processing facilities, and transmission and storage facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;

Table 8-19. Summary of the Model Plant Cost Effectiveness for Monthly Gas Imaging Monitoring

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	N/A	N/A	N/A	$15,390	$21,373	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$64,820	$37,049	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$537,313	$189,174	N/A	N/A	N/A	N/A
Gathering and Boosting Stations									
1	N/A	N/A	N/A	$149,051	$59,790	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$240,491	$86,135	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$329,687	$11,940	N/A	N/A	N/A	N/A
Processing Plants									
1	N/A	N/A	N/A	$92,522	$76,581	N/A	N/A	N/A	N/A
Transmission/Storage Facilities									
1	N/A	N/A	N/A	$20,817	$45,080	N/A	N/A	N/A	N/A

Note: This option only provides the number and magnitude of the leaks. Therefore, the emission reduction from this program cannot be quantified and the cost effectiveness values calculated.

- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

The following sections discuss these regulatory options.

8.5.1 Evaluation of Regulatory Options for Equipment Leaks

8.5.1.1 Well pads

The first regulatory option of a subpart VVa LDAR program was evaluated for well pads, which include the wells, processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. For well pads the VOC cost effectiveness for the model plants ranged from $267,386 per ton of VOC for a single well head facility to $6,934 ton of VOC for a well pad servicing 48 wells. Because of the high VOC cost effectiveness, Regulatory Option 1 was rejected for well pads.

The second regulatory option that was evaluated for well pads was Regulatory Option 2, which would require the implementation of a component subpart VVa LDAR program. The VOC cost effectiveness of this option ranged from $15,063 for valves to $211,992 for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option ranged from $5,364 per ton of VOC for Model Plant 3to $245,024 per ton of VOC for Model Plant 1. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.2 Gathering and Boosting Stations

The first regulatory option was evaluated for gathering and boosting stations which include the processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. The VOC cost effectiveness for the gathering and boosting model plants ranged from $10,327 per ton of VOC for

Model Plant 1 to $8,174per ton of VOC for Model Plant 3. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second regulatory option that was evaluated for gathering and boosting stations was Regulatory Option 2. The VOC cost effectiveness of this option ranged from $6,079 for valves to $77,310 per ton of VOC for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was also rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $10,724 per ton of VOC for Model Plant 1 and $8,685 per ton of VOC for Model Plant 3. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.3 Processing Plants

The VOC cost effectiveness of the first regulatory option was calculated to be $3,352 per ton of VOC. This cost effectiveness was determined to be reasonable and therefore this regulatory option was accepted.

The second option was evaluated for processing plants and the VOC cost effectiveness ranged from $0 for open-ended lined and pressure relief devices to $4,360 for connectors. Because the emission benefits and the cost effectiveness of Regulatory Option 1 were accepted, this option was not accepted.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $6,462 per ton of VOC and was determined to be not cost effective. Therefore, this regulatory option was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.4 Transmission and Storage Facilities

The first regulatory option was evaluated for transmission and storage facilities which include separators and dehydrators, as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. This sector moves processed gas from the processing facilities to the city gates. The VOC cost effectiveness for Regulatory Option 1 was $19,769per ton of VOC. The high VOC cost effectiveness is due to the inherent low VOC concentration in the processed natural gas, therefore the VOC reductions from this sector are low in comparison to the other sectors. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second option was evaluated for transmission facilities and the VOC cost effectiveness ranged from $24,762 for open-ended lined to $243,525 for connectors. This option was not accepted because of the high cost effectiveness.

The third regulatory option that was evaluated for transmission and storage facilities was Regulatory Option 3. The VOC cost effectiveness of this option was calculated to be $19,723 per ton of VOC. Again, because of the low VOC content of the processed gas, the regulatory option has a low VOC reduction. This cost was determined to be unreasonable and therefore this regulatory option was also rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.2 Nationwide Impacts of Regulatory Options

Regulatory Option 1 was selected as an option for setting standards for equipment leaks at processing plants. This option would require the implementation of an LDAR program using the subpart VVa requirements. For production facilities, 29 facilities per year are expected to be affected sources by the NSPS regulation annually. Table 8-20 provides a summary of the expected emission reductions from the implementation of this option.

Table 8-20. Nationwide Emission and Cost Analysis of Regulatory Options

Category	Estimated Number of Sources subject to NSPS	Facility Capital Cost ($)	Nationwide Emission Reductions (tpy)			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2 (Subpart VVa LDAR Program)												
Processing Plants	29	$7,522	392	1,407	14.7	$3,352	$2,517	$931	$699	0.218	1.31	0.984

8.6 References

1 Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards. September 2, 2008.

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APPENDIX A

E&P TANKS ANALYSIS FOR STORAGE VESSELS

Tank ID	**Sample Tank No. 1**	**Sample Tank No. 2**	**Sample Tank No. 3**	**Sample Tank No. 4**	**Sample Tank No. 5**	**Sample Tank No. 6**	**Sample Tank No. 7**	**Sample Tank No. 8**
E&P Tank Number	**Tank No. 58**	**Tank No. 59**	**Tank No. 60**	**Tank No. 61**	**Tank No. 62**	**Tank No. 63**	**Tank No. 64**	**Tank No. 65**
Total Emissions (tpy)	289.778	230.196	129.419	129.853	201.547	738.511	294.500	142.371
VOC Emissions (tpy)	43.734	111.414	101.853	63.343	154.313	578.379	205.794	89.728
Methane Emissions (tpy)	0.197	56.006	10.064	50.910	8.343	47.831	26.305	24.276
HAP Emissions (tpy)	**4.236**	**13.100**	**5.050**	**2.730**	**3.500**	**37.840**	**4.480**	**2.680**
Benzene	*0.828*	*6.343*	*0.501*	*0.285*	*0.051*	*7.568*	*0.116*	*0.219*
Toluene	*1.194*	*3.539*	*0.648*	*0.243*	*0.067*	*5.950*	*0.085*	*0.301*
E-Benzene	*0.041*	*0.083*	*0.040*	*0.008*	*0.002*	*0.086*	*0.006*	*0.020*
Xylenes	*0.165*	*0.327*	*0.233*	*0.066*	*0.046*	*0.679*	*0.018*	*0.152*
n-C6	*2.008*	*2.809*	*3.623*	*2.132*	*3.333*	*23.553*	*4.252*	*1.989*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	66	66	13	64	28	95	29	44
Separator Temperature (F)	83	90	110	74	78	118	60	71
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	83	90	110	74	78	118	60	71
C10+ SG	0.848	0.865	0.879	0.866	0.864	0.862	0.841	0.849
C10+ MW	234	237	294	301	281	312	224	349
API Gravity	**40.0**	**40.0**	**40.0**	**40.0**	**42.0**	**42.0**	**44.0**	**44.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	4.10	4.80	3.90	4.20	8.10	5.70	7.00
GOR (scf/bbl)	25.96	30.32	12.30	19.58	19.68	68.74	32.46	16.92
Heating Value of Vapor (Btu/s	398.80	1689.70	2486.42	1567.19	2261.27	2529.29	2162.56	2003.83
LP Oil Component	mol %							
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	5.0200	0.2700	0.0000	0.0800	0.0400	0.0000	0.0100	0.0200
N2	0.0000	0.0100	0.0000	0.0200	0.3100	0.0200	0.0200	0.0100
C1	0.0100	2.2600	0.4700	2.6500	0.4000	2.2500	1.1300	1.2900
C2	0.0400	1.2000	0.4800	0.3900	0.6500	3.1100	1.4100	1.0300
C3	0.2000	1.3200	1.5800	0.9200	1.7500	4.1100	3.2900	2.3000
i-C4	0.2800	0.7100	0.6200	0.9800	0.9200	1.3300	0.4500	1.1200
n-C4	0.4800	1.0800	2.6100	1.4700	2.4500	3.8100	4.0200	3.2200
i-C5	0.7600	1.2000	1.8100	2.0500	2.3900	2.5400	0.7000	2.3600
n-C5	0.7400	1.1300	2.9300	2.1600	2.9500	3.5100	4.0700	2.9600
C6	1.5100	2.0000	3.8800	3.4500	2.7600	3.0900	0.9600	3.0600
C7	4.6600	6.7600	10.7300	7.9400	10.8800	8.0100	5.5900	9.5000
C8	6.6100	9.4200	12.5300	9.6900	11.6400	7.6800	5.5200	11.5900
C9	4.8700	6.5600	6.9400	6.5600	6.1800	4.4400	4.2700	6.3200
C10+	70.1100	49.2600	47.3100	56.3900	52.0200	47.6400	63.0500	47.7200
Benzene	0.5700	4.9100	0.5800	0.4300	0.0700	1.3400	0.1600	0.3600
Toluene	2.1400	7.7900	1.9900	1.1000	0.2700	2.6800	0.3700	1.4900
E-Benzene	0.1700	0.4600	0.2900	0.1000	0.0200	0.0900	0.0700	0.2600
Xylenes	0.7600	2.0500	1.9000	0.9000	0.5500	0.8000	0.2500	2.2900
n-C6	1.0700	1.6100	3.3500	2.7200	3.7500	3.5500	4.6600	3.1000
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 9**	**Sample Tank No. 10**	**Sample Tank No. 11**	**Sample Tank No. 12**	**Sample Tank No. 13**	**Sample Tank No. 14**	**Sample Tank No. 15**
E&P Tank Number	**Tank No. 66**	**Tank No. 67**	**Tank No. 68**	**Tank No. 69**	**Tank No. 70**	**Tank No. 71**	**Tank No. 72**
Total Emissions (tpy)	357.688	134.789	314.446	505.131	306.443	256.029	1061.274
VOC Emissions (tpy)	243.348	79.118	224.158	437.555	252.987	204.571	987.647
Methane Emissions (tpy)	56.846	37.876	18.892	21.472	15.159	21.237	32.940
HAP Emissions (tpy)	**5.590**	**5.680**	**7.030**	**13.450**	**15.330**	**6.500**	**56.780**
Benzene	*0.244*	*1.308*	*0.242*	*0.119*	*1.048*	*0.464*	*5.791*
Toluene	*0.440*	*1.184*	*0.385*	*0.146*	*1.488*	*0.927*	*6.793*
E-Benzene	*0.039*	*0.029*	*0.043*	*0.019*	*0.062*	*0.051*	*0.303*
Xylenes	*0.208*	*0.488*	*0.167*	*0.162*	*0.734*	*0.590*	*4.255*
n-C6	*4.661*	*2.671*	*6.191*	*13.008*	*12.001*	*4.468*	*39.634*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	41	20	23	24	52	45
Separator Temperature (F)	60	72	68	85	114	108	140
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	72	68	85	114	108	140
C10+ SG	0.878	0.854	0.926	0.848	0.87	0.886	0.893
C10+ MW	270	270	290	275	274	269	277
API Gravity	**44.0**	**45.0**	**45.0**	**46.0**	**46.0**	**47.0**	**47.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.10	5.20	8.10	4.70	5.00	5.30	6.00
GOR (scf/bbl)	41.30	17.66	30.80	43.26	26.30	24.28	78.80
Heating Value of Vapor (Btu/s	2060.54	1812.87	2234.66	2651.81	2611.90	2491.55	3120.85
LP Oil Component							
H2S	0.0000	0.0000	0.0000	0.0500	0.0700	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0400	0.3100	0.2400	0.1700	0.0000	0.0400
N2	0.0000	0.0100	0.0200	0.0100	0.0000	0.0000	0.0000
C1	2.3400	1.8400	0.6900	0.9400	0.6200	0.9700	1.2100
C2	1.5600	0.6100	0.9400	0.6600	0.5200	0.7700	0.7600
C3	3.8500	1.2700	2.7300	2.1500	1.6800	2.0200	2.9200
i-C4	1.3600	0.8900	1.7300	1.1100	0.9900	1.5500	4.1500
n-C4	3.9600	1.5600	3.9300	4.5400	3.1200	2.1400	3.0600
i-C5	3.1300	1.8000	3.8800	3.0600	2.4500	3.3400	3.9300
n-C5	4.0300	1.8800	4.1000	4.9800	3.4200	2.8800	3.0900
C6	3.6100	3.4300	5.1500	4.1100	4.4300	3.2600	4.9100
C7	7.7900	10.7400	12.0700	10.2100	8.8900	9.0800	13.0800
C8	13.7700	12.6900	18.2000	10.6800	18.5800	11.7900	14.6200
C9	4.8300	7.8700	8.8800	5.4300	8.7200	5.8500	7.6300
C10+	42.2300	43.0100	27.3600	45.2800	36.2600	49.3100	31.1400
Benzene	0.2400	1.5600	0.3000	0.0600	0.5300	0.3000	0.6900
Toluene	1.3400	3.8100	1.4700	0.2100	1.9700	1.6000	1.9400
E-Benzene	0.3200	0.2200	0.4400	0.0700	0.1900	0.2100	0.1900
Xylenes	1.9700	4.1900	1.9600	0.6700	2.5500	2.7300	2.9800
n-C6	3.6200	2.5800	5.8400	5.5400	4.8400	2.2000	3.6600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 16**	**Sample Tank No. 17**	**Sample Tank No. 18**	**Sample Tank No. 19**	**Sample Tank No. 20**	**Sample Tank No. 21**
E&P Tank Number	**Tank No. 73**	**Tank No. 74**	**Tank No. 75**	**Tank No. 76**	**Tank No. 77**	**Tank No. 78**
Total Emissions (tpy)	464.597	214.658	1331.488	3972.618	540.533	1228.897
VOC Emissions (tpy)	383.349	135.482	1146.617	2331.105	399.555	940.078
Methane Emissions (tpy)	18.132	32.283	31.967	755.826	38.624	105.184
HAP Emissions (tpy)	**10.980**	**7.530**	**77.780**	**82.380**	**7.580**	**13.230**
Benzene	*0.222*	*1.269*	*7.661*	*12.470*	*2.447*	*0.543*
Toluene	*0.208*	*0.708*	*3.775*	*23.584*	*1.643*	*0.466*
E-Benzene	*0.058*	*0.019*	*0.113*	*0.056*	*0.051*	*0.006*
Xylenes	*0.193*	*0.411*	*0.929*	*0.635*	*0.256*	*0.052*
n-C6	*10.296*	*5.124*	*65.304*	*45.632*	*3.186*	*12.160*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	40	31	50	700	20	98
Separator Temperature (F)	76	76	125	100	48	40
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	76	76	125	100	48	40
C10+ SG	0.885	0.839	0.842	0.878	0.877	0.929
C10+ MW	318	296	287	178	179	324
API Gravity	**47.0**	**49.0**	**49.0**	**50.0**	**50.0**	**51.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.60	5.00	8.90	7.40	9.40	11.20
GOR (scf/bbl)	41.32	24.48	106.60	491.90	56.44	128.16
Heating Value of Vapor (Btu/s	2421.27	2045.68	2822.40	1916.15	2275.04	2279.83
LP Oil Component						
H2S	0.0000	0.0000	1.2800	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0400	0.0800	0.0300	0.4200	0.0100	0.0100
N2	0.8400	0.0100	0.0000	0.0700	0.0100	0.0400
C1	0.7800	1.4000	1.2700	15.3300	1.1400	3.2200
C2	0.7500	0.9700	2.0800	8.9600	1.6000	2.9500
C3	3.5300	1.3500	4.5700	8.2100	4.0100	6.4800
i-C4	2.0700	1.0500	1.8900	2.3100	2.3400	2.2000
n-C4	6.8800	2.4200	6.4800	4.1900	4.7300	8.5300
i-C5	5.0000	2.7100	3.8800	2.4300	4.1700	4.6800
n-C5	7.4800	3.2900	7.0400	2.3500	2.9700	7.4700
C6	4.1000	4.6900	3.0500	3.1100	4.3800	5.7300
C7	11.3200	11.3500	6.8200	8.4700	8.8100	15.8300
C8	11.7900	12.4100	7.7800	8.8400	12.3800	12.6400
C9	6.1100	9.3100	7.2300	3.7100	5.4900	4.0800
C10+	32.0700	36.0900	37.9300	23.5600	32.1400	18.1600
Benzene	0.1400	1.4000	0.8300	0.8200	2.8900	0.3400
Toluene	0.3800	2.3200	1.0200	4.6700	6.4200	1.0200
E-Benzene	0.2700	0.1600	0.0700	0.0300	0.5700	0.0400
Xylenes	1.0300	4.0200	0.6500	0.3900	3.3000	0.4000
n-C6	5.4200	4.9700	6.1000	2.1300	2.6400	6.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 22**	**Sample Tank No. 23**	**Sample Tank No. 24**	**Sample Tank No. 25**	**Sample Tank No. 26**	**Sample Tank No. 27**
E&P Tank Number	**Tank No. 79**	**Tank No. 80**	**Tank No. 81**	**Tank No. 82**	**Tank No. 83**	**Tank No. 84**
Total Emissions (tpy)	362.298	790.092	557.188	5007.636	175.911	714.052
VOC Emissions (tpy)	175.304	665.349	483.599	3386.300	77.584	639.895
Methane Emissions (tpy)	109.676	24.115	10.288	842.206	54.660	18.553
HAP Emissions (tpy)	**7.150**	**28.770**	**14.580**	**101.610**	**4.770**	**30.190**
Benzene	*0.353*	*3.892*	*1.930*	*9.782*	*0.929*	*4.165*
Toluene	*0.102*	*6.465*	*1.651*	*12.547*	*0.909*	*2.542*
E-Benzene	*0.120*	*0.119*	*0.055*	*0.040*	*0.050*	*0.192*
Xylenes	*0.437*	*2.017*	*0.631*	*0.716*	*0.221*	*1.424*
n-C6	*6.133*	*16.273*	*10.317*	*78.528*	*2.665*	*21.871*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	115	30	15	770	39	38
Separator Temperature (F)	73	100	86	100	66	95
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	73	100	86	100	66	95
C10+ SG	0.873	0.901	0.878	0.858	0.854	0.823
C10+ MW	200	220	254	195	175	375
API Gravity	**54.0**	**54.0**	**54.0**	**55.0**	**57.0**	**57.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	5.30	9.40	10.30	7.80	5.70	9.60
GOR (scf/bbl)	51.34	68.32	47.12	578.20	25.46	57.38
Heating Value of Vapor (Btu/s	1678.80	2676.21	2764.90	2043.18	1632.00	2897.16
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.1100	0.0200	0.5500	0.0700	0.0400
N2	0.0300	0.0200	0.0100	0.0300	0.0000	0.0000
C1	3.5600	0.7100	0.3300	16.1500	1.7200	0.7000
C2	1.4300	1.5400	1.0900	7.1400	0.9000	1.0900
C3	1.8700	4.5900	3.8300	9.6600	1.3800	3.5600
i-C4	0.6800	2.3400	3.7000	3.8100	1.0000	2.9000
n-C4	2.0000	4.4400	4.8700	5.9600	1.4900	6.2100
i-C5	1.6600	3.9000	4.4800	3.5300	1.4600	6.0400
n-C5	2.0600	3.8000	3.9800	3.7200	1.5300	5.8400
C6	2.4100	5.0900	6.0500	3.8400	4.0600	7.3200
C7	15.0800	12.9700	15.6400	8.7600	14.5700	13.0000
C8	25.1900	19.0700	17.5800	8.9200	23.7200	12.2200
C9	12.4900	6.9500	6.1000	3.1000	13.7700	7.9600
C10+	24.3900	18.9200	21.1300	17.9300	20.9800	20.0200
Benzene	0.2400	1.2000	1.0500	0.5800	1.4900	1.2200
Toluene	0.2100	5.5400	2.6000	2.3000	4.5300	2.0500
E-Benzene	0.6600	0.2500	0.2200	0.0200	0.6700	0.3800
Xylenes	2.7600	4.8300	2.8900	0.4200	3.4200	3.2200
n-C6	3.1900	3.7300	4.4300	3.5800	3.2400	6.2300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 28**	**Sample Tank No. 29**	**Sample Tank No. 30**	**Sample Tank No. 31**	**Sample Tank No. 32**	**Sample Tank No. 33**
E&P Tank Number	**Tank No. 85**	**Tank No. 86**	**Tank No. 87**	**Tank No. 88**	**Tank No. 89**	**Tank No. 90**
Total Emissions (tpy)	801.228	983.881	4326.573	3074.670	2951.879	616.490
VOC Emissions (tpy)	757.176	750.313	2406.579	1892.668	1439.584	332.126
Methane Emissions (tpy)	5.307	49.123	1088.727	746.499	999.175	120.918
HAP Emissions (tpy)	**29.510**	**14.080**	**58.180**	**47.230**	**44.040**	**9.140**
Benzene	*3.415*	*1.119*	*4.653*	*5.891*	*1.409*	*0.576*
Toluene	*5.329*	*1.453*	*5.785*	*6.575*	*2.934*	*1.658*
E-Benzene	*0.192*	*0.049*	*0.186*	*0.022*	*0.159*	*0.079*
Xylenes	*1.786*	*0.263*	*0.989*	*0.316*	*1.136*	*0.806*
n-C6	*18.788*	*11.194*	*46.561*	*34.427*	*38.406*	*6.016*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	65	54	870	600	780	60
Separator Temperature (F)	80	60	78	70	70	56
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	80	60	78	70	70	60
C10+ SG	0.899	0.868	0.868	0.847	0.905	0.905
C10+ MW	166	268	268	176	174	174
API Gravity	**57.0**	**57.0**	**57.0**	**57.0**	**58.0**	**58.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.80	13.10	13.10	7.50	8.00	8.00
GOR (scf/bbl)	61.26	97.00	578.20	396.24	436.98	79.54
Heating Value of Vapor (Btu/s	3046.83	2390.47	1789.23	1831.51	1633.60	1851.14
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	0.0800	0.4200	0.5800	0.2700	0.0800
N2	0.0000	0.0000	0.0800	0.0200	0.0200	0.0100
C1	0.1500	1.4800	21.2000	16.0200	20.3000	3.3900
C2	0.5700	2.9100	8.2900	4.1200	5.1800	2.4300
C3	2.4100	6.9600	8.5400	6.9000	5.6800	3.8400
i-C4	1.7300	2.6300	2.3000	2.7500	1.4200	1.3000
n-C4	3.5500	7.2100	5.8400	4.9100	4.1400	3.2000
i-C5	4.1400	4.6400	3.3500	3.6000	2.5400	2.4100
n-C5	3.8600	5.7100	4.0400	3.9000	3.1000	2.5600
C6	6.5100	5.0100	3.4200	3.9500	3.7700	3.7700
C7	18.7100	13.5500	9.1200	10.3800	11.2200	13.2600
C8	19.4300	15.0600	10.0900	11.3000	14.7500	22.4400
C9	6.8400	6.2300	4.1700	4.2100	7.0600	11.1300
C10+	15.5200	18.8400	12.5900	19.2800	13.5400	16.0600
Benzene	1.1800	0.5900	0.4000	0.8200	0.1800	0.4100
Toluene	5.2100	2.5000	1.6800	3.0600	1.2600	3.8600
E-Benzene	0.4600	0.2400	0.1600	0.0300	0.2000	0.5200
Xylenes	4.8600	1.4900	1.0000	0.5000	1.6700	6.1500
n-C6	4.8600	4.8700	3.3100	3.6700	3.7000	3.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 34**	**Sample Tank No. 35**	**Sample Tank No. 36**	**Sample Tank No. 37**	**Sample Tank No. 38**	**Sample Tank No. 39**
E&P Tank Number	**Tank No. 91**	**Tank No. 92**	**Tank No. 93**	**Tank No. 94**	**Tank No. 95**	**Tank No. 96**
Total Emissions (tpy)	2575.122	2774.089	653.459	3495.242	363.650	4744.399
VOC Emissions (tpy)	1494.749	2092.925	394.781	2876.860	223.772	3658.384
Methane Emissions (tpy)	581.208	346.071	121.446	169.818	84.912	381.967
HAP Emissions (tpy)	**65.980**	**48.710**	**14.210**	**93.030**	**10.760**	**89.970**
Benzene	*9.303*	*2.750*	*0.871*	*10.232*	*0.500*	*11.564*
Toluene	*14.114*	*2.311*	*2.688*	*11.558*	*0.279*	*11.735*
E-Benzene	*0.019*	*0.128*	*0.136*	*0.034*	*0.060*	*0.033*
Xylenes	*0.409*	*0.872*	*1.400*	*0.580*	*0.256*	*0.472*
n-C6	*42.130*	*42.650*	*9.111*	*70.629*	*9.661*	*66.162*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	500	300	110	750	85	730
Separator Temperature (F)	84	80	72	90	85	84
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	84	80	72	90	85	84
C10+ SG	0.909	0.882	0.901	0.898	0.9	0.898
C10+ MW	204	296	162	215	202	225
API Gravity	**58.0**	**58.0**	**59.0**	**60.0**	**61.0**	**61.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	9.10	10.60	10.00	9.40	7.00	9.80
GOR (scf/bbl)	323.88	287.10	79.90	320.48	45.04	475.20
Heating Value of Vapor (Btu/s	1892.64	2289.04	1946.32	2541.49	1921.87	2340.56
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.2300	0.0300	0.0800	0.3400	0.0400	0.4100
N2	0.0600	0.0900	0.0100	0.0200	0.0200	0.0300
C1	12.9800	8.4300	3.3900	3.7500	2.6100	7.3900
C2	5.7800	4.2300	2.4300	4.7700	1.1600	6.6400
C3	4.6400	5.9100	3.8400	9.2600	2.2100	10.9400
i-C4	2.0900	5.1700	1.3000	4.8100	0.9300	4.5800
n-C4	4.1800	6.2200	3.2000	7.0200	2.4900	8.3400
i-C5	4.9600	8.9100	2.4100	5.5900	2.1300	5.5000
n-C5	4.0700	4.9700	2.5600	6.1200	2.9200	5.8200
C6	6.0700	9.1100	3.7700	6.1300	3.5400	5.3200
C7	13.1100	11.3400	13.2600	12.8200	19.5300	11.2900
C8	11.9500	10.3900	22.4400	12.5200	27.1600	11.1800
C9	4.8600	5.9600	11.1300	4.0100	14.7000	3.1900
C10+	14.1100	11.7500	16.0600	11.4200	13.8800	8.8000
Benzene	1.1400	0.3700	0.4100	1.1000	0.2900	1.1400
Toluene	5.4100	0.9800	3.8600	3.7900	0.4700	3.7600
E-Benzene	0.0200	0.1500	0.5200	0.0300	0.2600	0.0300
Xylenes	0.5000	1.1900	6.1500	0.5900	1.2600	0.5000
n-C6	3.8400	4.8000	3.1800	5.9100	4.4000	5.1400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 40**	**Sample Tank No. 41**	**Sample Tank No. 42**	**Sample Tank No. 43**	**Sample Tank No. 44**	**Sample Tank No. 45**
E&P Tank Number	**Tank No. 97**	**Tank No. 98**	**Tank No. 99**	**Tank No. 100**	**Tank No. 101**	**Tank No. 102**
Total Emissions (tpy)	907.495	277.197	3410.034	2122.607	8152.118	6780.555
VOC Emissions (tpy)	734.651	158.333	2732.261	1066.705	5678.554	4276.160
Methane Emissions (tpy)	49.578	75.426	159.904	736.341	1206.981	1045.765
HAP Emissions (tpy)	**24.160**	**8.820**	**67.500**	**64.680**	**81.710**	**48.890**
Benzene	*1.573*	*0.204*	*9.290*	*9.500*	*10.844*	*5.934*
Toluene	*3.102*	*0.854*	*9.192*	*15.007*	*8.516*	*1.416*
E-Benzene	*0.094*	*0.042*	*0.016*	*0.161*	*0.012*	*0.222*
Xylenes	*1.079*	*0.375*	*0.371*	*1.585*	*0.288*	*1.359*
n-C6	*18.314*	*7.344*	*48.628*	*38.425*	*62.050*	*39.961*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	57	72	730	580	730	807
Separator Temperature (F)	82	80	80	77	80	96
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	82	80	80	77	80	96
C10+ SG	0.884	0.869	0.883	0.85	0.895	0.811
C10+ MW	240	190	226	190	197	173
API Gravity	**62.0**	**63.0**	**63.0**	**64.0**	**64.0**	**66.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.40	7.00	11.90	6.40	11.00	11.80
GOR (scf/bbl)	84.20	36.56	321.62	309.64	924.96	804.54
Heating Value of Vapor (Btu/s	2521.70	1805.12	2477.18	1622.20	2083.02	2013.21
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0800	0.0400	0.3200	0.0700	0.5600	0.2200
N2	0.0100	0.0300	0.0200	0.0700	0.0300	0.0800
C1	1.4000	2.3500	3.4800	16.3500	16.9100	16.2600
C2	1.7700	1.0000	5.5300	3.6400	8.6200	11.7100
C3	4.8200	2.0700	10.1700	3.5600	12.0400	11.6100
i-C4	2.8200	0.7100	4.9900	1.6900	5.2700	4.3900
n-C4	5.9700	2.2600	8.1400	2.9800	9.0700	7.5600
i-C5	4.3100	1.7000	5.8700	2.6800	5.6500	4.5200
n-C5	4.1900	2.7400	6.1600	2.7900	5.8200	3.9400
C6	6.5100	3.4900	5.7200	3.8200	5.1000	3.3600
C7	17.7500	17.7300	12.3800	18.1400	8.0600	5.9200
C8	18.6400	27.9100	12.3100	19.4700	7.5500	11.6900
C9	7.4400	16.1500	3.7900	4.5900	2.2200	5.9200
C10+	11.6100	12.2800	9.9100	6.7300	5.6700	8.9300
Benzene	0.5600	0.1600	1.2800	1.2200	0.8500	0.3700
Toluene	3.2800	1.9800	4.0500	6.0700	2.3800	0.3000
E-Benzene	0.2600	0.2500	0.0200	0.1800	0.0100	0.1400
Xylenes	3.4100	2.5800	0.5300	2.0600	0.2900	1.0100
n-C6	5.1700	4.5700	5.3300	3.8900	3.9000	2.0700
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 46**	**Sample Tank No. 47**	**Sample Tank No. 48**	**Sample Tank No. 49**	**Sample Tank No. 50**	**Sample Tank No. 51**
E&P Tank Number	**Tank No. 103**	**Tank No. 1**	**Tank No. 2**	**Tank No. 3**	**Tank No. 4**	**Tank No. 5**
Total Emissions (tpy)	927.902	95.816	112.738	74.503	155.244	93.073
VOC Emissions (tpy)	623.038	6.175	61.936	28.446	61.470	51.471
Methane Emissions (tpy)	167.129	0.115	1.927	0.309	46.064	0.440
HAP Emissions (tpy)	**20.320**	**0.460**	**2.960**	**0.990**	**1.760**	**3.190**
Benzene	*1.625*	*0.006*	*0.076*	*0.012*	*0.010*	*0.218*
Toluene	*1.876*	*0.013*	*0.060*	*0.031*	*0.037*	*0.074*
E-Benzene	*0.062*	*0.007*	*0.019*	*0.002*	*0.025*	*0.006*
Xylenes	*0.696*	*0.018*	*0.105*	*0.041*	*0.069*	*0.048*
n-C6	*16.059*	*0.421*	*2.704*	*0.904*	*1.616*	*2.845*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	170	45	22	20	53	15
Separator Temperature (F)	75	106	155	160	101	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	75	106	155	160	101	120
C10+ SG	0.801	0.972	0.972	0.952	0.961	0.984
C10+ MW	196	425	436	458	394	551
API Gravity	**68.0**	**15.0**	**17.0**	**18.0**	**19.0**	**19.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	12.50	0.80	2.00	0.60	2.30	4.80
GOR (scf/bbl)	106.60	8.88	9.60	6.44	17.78	7.52
Heating Value of Vapor (Btu/s	2081.33	181.43	1738.61	1076.97	1365.68	1718.17
LP Oil Component						
H2S	0.0000	0.1100	0.0000	0.0400	0.5100	0.1400
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	2.8500	1.3000	1.5400	1.1900	1.5000
N2	0.0100	0.0000	0.0000	0.0300	0.0100	0.0000
C1	4.9300	0.0100	0.1500	0.0300	1.5300	0.0400
C2	2.5800	0.0100	0.4000	0.0400	0.5300	0.2400
C3	3.4200	0.0200	0.7800	0.2200	0.8100	0.8500
i-C4	3.4300	0.0500	0.5600	0.1600	0.5000	0.6500
n-C4	3.7300	0.1800	1.2600	0.4700	1.2000	1.6500
i-C5	5.5500	0.3200	0.8700	0.4300	1.1500	2.1900
n-C5	3.6500	0.4500	1.2400	0.6500	1.3400	3.1500
C6	8.0700	0.6000	1.9800	0.6100	1.7500	4.7300
C7	14.6500	1.7200	3.4500	1.5800	3.6200	6.2500
C8	13.2600	2.1800	4.2600	2.0700	3.5300	10.2800
C9	7.8000	1.8400	3.6600	2.2800	3.5300	5.9300
C10+	19.6300	88.7100	78.1500	88.9700	76.8100	57.9100
Benzene	0.5400	0.0100	0.0500	0.0100	0.0100	0.3000
Toluene	1.9200	0.0600	0.0900	0.0600	0.1000	0.2600
E-Benzene	0.1700	0.0800	0.0600	0.0100	0.1600	0.0500
Xylenes	2.2200	0.2300	0.3700	0.1800	0.5100	0.4300
n-C6	4.4300	0.5700	1.3700	0.6200	1.2100	3.4500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 52**	**Sample Tank No. 53**	**Sample Tank No. 54**	**Sample Tank No. 55**	**Sample Tank No. 56**	**Sample Tank No. 57**
E&P Tank Number	**Tank No. 6**	**Tank No. 7**	**Tank No. 8**	**Tank No. 9**	**Tank No. 10**	**Tank No. 11**
Total Emissions (tpy)	24.484	26.091	29.739	114.630	42.075	
VOC Emissions (tpy)	3.087	17.629	11.288	74.707	8.263	
Methane Emissions (tpy)	15.587	2.836	5.908	25.400	27.176	
HAP Emissions (tpy)	**0.190**	**0.510**	**0.330**	**2.120**	**0.090**	
Benzene	*0.003*	*0.007*	*0.013*	*0.039*	*0.028*	
Toluene	*0.006*	*0.014*	*0.008*	*0.071*	*0.010*	
E-Benzene	*0.000*	*0.001*	*0.003*	*0.007*	*0.000*	
Xylenes	*0.005*	*0.012*	*0.007*	*0.090*	*0.001*	
n-C6	*0.175*	*0.474*	*0.298*	*1.919*	*0.052*	
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	
Separator Pressure (psig)	23	17	18	54	35	
Separator Temperature (F)	79	106	75	125	76	
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	
Ambient Temperature (F)	79	106	75	125	76	
C10+ SG	0.947	0.967	0.963	0.943	0.923	
C10+ MW	368	383	401	363	278	
API Gravity	**20.0**	**20.0**	**20.0**	**21.0**	**23.0**	
Production Rate (bbl/day)	500	500	500	500	500	
Reid Vapor Pressure (psia)	1.20	3.30	3.80	1.10	1.80	
GOR (scf/bbl)	4.98	2.82	3.94	13.90	8.52	
Heating Value of Vapor (Btu/s	1067.32	2208.23	1236.41	1980.20	1192.63	
LP Oil Component						
H2S	0.0100	0.0000	0.0000	0.0000	0.0000	
O2	0.0000	0.0000	0.0000	0.0000	0.0000	
CO2	0.0700	0.0000	0.2500	0.0000	0.0600	
N2	0.0900	0.0000	0.2100	0.0100	0.0100	
C1	1.2500	0.1900	0.5300	1.8000	1.7700	
C2	0.2000	0.2300	0.3300	0.5400	0.2900	
C3	0.0800	0.7500	0.7500	0.5200	0.3700	
i-C4	0.0900	0.4900	0.4900	0.2800	0.2300	
n-C4	0.1800	1.5700	1.5000	0.9200	0.3100	
i-C5	0.4000	1.5300	1.3500	0.9800	0.4900	
n-C5	0.4500	1.9100	1.7700	0.9700	0.2400	
C6	1.0500	2.7500	2.3700	1.6800	0.2500	
C7	2.3300	3.9000	4.3000	3.0100	0.5900	
C8	2.9800	6.8100	5.5200	3.7300	0.5000	
C9	2.6000	4.0100	3.5700	3.5400	0.2500	
C10+	87.0300	73.0300	74.2800	80.2500	94.2100	
Benzene	0.0200	0.0400	0.1000	0.0300	0.1100	
Toluene	0.1100	0.2200	0.1900	0.1400	0.1200	
E-Benzene	0.0200	0.0500	0.1900	0.0300	0.0100	
Xylenes	0.2700	0.5100	0.4700	0.4500	0.0500	
n-C6	0.7700	2.0100	1.8300	1.1200	0.1400	
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	
	100.0000	100.0000	100.0000	100.0000	100.0000	0.0000

Tank ID	**Sample Tank No. 58**	**Sample Tank No. 59**	**Sample Tank No. 60**	**Sample Tank No. 61**	**Sample Tank No. 62**	**Sample Tank No. 63**
E&P Tank Number	**Tank No. 12**	**Tank No. 13**	**Tank No. 14**	**Tank No. 15**	**Tank No. 16**	**Tank No. 17**
Total Emissions (tpy)	134.719	26.214	195.573	142.068	191.224	35.095
VOC Emissions (tpy)	63.729	5.207	109.615	69.135	105.838	25.578
Methane Emissions (tpy)	16.689	12.924	7.759	5.438	4.313	3.029
HAP Emissions (tpy)	**1.170**	**0.430**	**2.810**	**1.760**	**2.110**	**0.750**
Benzene	*0.020*	*0.008*	*0.033*	*0.024*	*0.041*	*0.011*
Toluene	*0.014*	*0.032*	*0.032*	*0.053*	*0.079*	*0.022*
E-Benzene	*0.007*	*0.002*	*0.023*	*0.003*	*0.003*	*0.003*
Xylenes	*0.027*	*0.019*	*0.064*	*0.041*	*0.016*	*0.011*
n-C6	*1.104*	*0.371*	*2.659*	*1.640*	*1.969*	*0.701*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	20	20	22	20	19
Separator Temperature (F)	66	122	88	86	68	133
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	66	122	88	86	68	133
C10+ SG	0.946	0.926	0.945	0.944	0.964	0.928
C10+ MW	382	336	381	404	444	327
API Gravity	**23.0**	**24.0**	**24.0**	**24.0**	**24.0**	**25.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.00	0.60	3.90	4.60	4.80	4.10
GOR (scf/bbl)	15.42	4.60	19.12	13.74	17.84	3.48
Heating Value of Vapor (Btu/s	1553.86	1059.39	1747.39	1543.44	1703.42	2314.31
LP Oil Component						
H2S	0.4400	0.0000	0.5200	0.4500	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.6400	0.1200	0.9600	1.1500	1.4200	0.0500
N2	0.0100	0.1000	0.1200	0.0200	0.0200	0.0000
C1	1.0700	0.9400	0.4900	0.3600	0.2700	0.2500
C2	0.5400	0.0500	0.6500	0.5000	0.6200	0.4900
C3	1.4100	0.0700	1.7300	1.5900	1.9400	1.1600
i-C4	0.7000	0.0600	0.7400	0.7600	1.1000	0.6000
n-C4	1.9400	0.1000	2.4600	2.4000	3.0100	1.5900
i-C5	1.8900	0.2400	1.7900	1.7300	2.1900	1.4300
n-C5	2.3600	0.2300	2.3100	2.1400	3.2100	1.4400
C6	2.7100	0.9100	2.6100	2.6400	3.9300	1.9900
C7	5.1800	2.8000	5.3300	5.5200	5.6800	3.5100
C8	5.3700	4.2200	5.5400	6.0700	11.3000	4.4100
C9	3.9800	4.3400	4.2100	4.6000	6.7600	4.4400
C10+	68.6500	84.5400	67.0700	66.9000	54.5000	76.8100
Benzene	0.0500	0.0200	0.0400	0.0400	0.0800	0.0300
Toluene	0.1100	0.2100	0.1100	0.2600	0.4700	0.1500
E-Benzene	0.1500	0.0300	0.2000	0.0400	0.0400	0.0400
Xylenes	0.6500	0.3100	0.6300	0.5800	0.2900	0.1800
n-C6	2.1500	0.7100	2.4900	2.2500	3.1700	1.4300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 64**	**Sample Tank No. 65**	**Sample Tank No. 66**	**Sample Tank No. 67**	**Sample Tank No. 68**	**Sample Tank No. 69**
E&P Tank Number	**Tank No. 18**	**Tank No. 19**	**Tank No. 20**	**Tank No. 21**	**Tank No. 22**	**Tank No. 23**
Total Emissions (tpy)	139.887	70.761	171.538	38.394	215.631	148.757
VOC Emissions (tpy)	89.426	46.290	110.120	12.834	164.956	138.780
Methane Emissions (tpy)	21.590	4.142	15.382	16.424	8.875	1.515
HAP Emissions (tpy)	**1.190**	**2.570**	**1.670**	**0.720**	**4.240**	**5.310**
Benzene	*0.011*	*0.371*	*0.013*	*0.224*	*0.985*	*1.086*
Toluene	*0.035*	*0.697*	*0.017*	*0.209*	*0.787*	*0.854*
E-Benzene	*0.010*	*0.039*	*0.004*	*0.007*	*0.020*	*0.025*
Xylenes	*0.025*	*0.176*	*0.025*	*0.066*	*0.118*	*0.122*
n-C6	*1.109*	*1.292*	*1.613*	*0.216*	*2.331*	*3.227*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	25	31	23	17	20
Separator Temperature (F)	60	136	64	79	86	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	136	64	79	86	120
C10+ SG	0.94	0.916	0.938	0.908	0.946	0.932
C10+ MW	380	431	340	324	323	326
API Gravity	**25.0**	**27.0**	**27.0**	**29.0**	**29.0**	**29.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	3.30	5.20	3.10	4.80	4.90
GOR (scf/bbl)	16.66	6.76	18.46	6.36	20.11	11.50
Heating Value of Vapor (Btu/s	1966.88	2041.97	1887.18	1405.21	2354.30	2985.81
LP Oil Component						
H2S	0.0000	0.3800	0.2400	0.0000	0.2700	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0600	0.2200	0.2100	0.0900	0.0800	0.0300
N2	0.0400	0.1000	0.3000	0.0000	0.0000	0.0000
C1	1.3500	0.3200	0.8600	1.1200	0.4400	0.0800
C2	0.8500	0.4100	0.5400	0.5300	0.7000	0.2000
C3	2.0900	1.0700	1.7500	0.7000	2.0600	1.3000
i-C4	1.1400	0.5700	1.1600	0.4500	0.9700	1.0400
n-C4	2.7100	1.4500	3.1500	0.6300	2.7500	3.8800
i-C5	2.1900	1.5700	2.9100	0.6400	2.7000	2.2100
n-C5	2.4600	1.5100	2.5900	0.4600	2.3200	3.2000
C6	2.2400	2.5400	3.7200	0.8400	3.5000	2.5500
C7	5.7900	3.5300	5.8600	4.7900	8.3100	7.2000
C8	4.7900	4.9600	5.6200	8.9000	7.2900	7.2300
C9	4.4800	4.1700	3.7300	5.8000	7.0500	4.7500
C10+	66.3000	72.0600	63.8500	67.7100	53.9500	59.2600
Benzene	0.0300	0.4300	0.0300	1.0000	1.2400	1.1600
Toluene	0.2900	1.9600	0.1200	2.7600	2.8500	2.3500
E-Benzene	0.2200	0.2400	0.0800	0.2400	0.1800	0.1600
Xylenes	0.6500	1.2100	0.5400	2.5900	1.2300	0.8600
n-C6	2.3200	1.3000	2.7400	0.7500	2.1100	2.5400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 70**	**Sample Tank No. 71**	**Sample Tank No. 72**	**Sample Tank No. 73**	**Sample Tank No. 74**	**Sample Tank No. 75**
E&P Tank Number	**Tank No. 24**	**Tank No. 25**	**Tank No. 26**	**Tank No. 27**	**Tank No. 28**	**Tank No. 29**
Total Emissions (tpy)	243.873	502.831	13.397	154.387	119.805	263.134
VOC Emissions (tpy)	151.292	330.274	4.231	125.001	48.333	168.558
Methane Emissions (tpy)	7.881	124.465	6.395	4.603	45.716	54.016
HAP Emissions (tpy)	**2.480**	**13.120**	**0.070**	**10.900**	**1.090**	**3.440**
Benzene	*0.188*	*0.954*	*0.008*	*0.053*	*0.189*	*0.435*
Toluene	*0.276*	*1.256*	*0.003*	*0.110*	*0.076*	*0.413*
E-Benzene	*0.007*	*0.086*	*0.000*	*0.031*	*0.004*	*0.046*
Xylenes	*0.114*	*0.732*	*0.008*	*0.305*	*0.033*	*0.285*
n-C6	*1.896*	*10.096*	*0.055*	*10.401*	*0.785*	*2.257*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	22	280	4	25	64	80
Separator Temperature (F)	98	106	80	180	70	77
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	98	106	80	180	70	77
C10+ SG	0.917	0.921	0.893	0.916	0.898	0.896
C10+ MW	311	450	313	304	368	309
API Gravity	**29.0**	**30.0**	**30.0**	**30.0**	**30.0**	**33.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	6.20	4.80	2.60	2.70	2.80	2.20
GOR (scf/bbl)	24.26	61.80	2.34	11.76	18.78	32.78
Heating Value of Vapor (Btu/s	2141.84	1933.26	1394.74	2814.20	1478.45	1920.70
LP Oil Component						
H2S	1.0100	0.0000	0.0000	0.0300	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1100	0.1200	0.0200	0.2700	0.1700	0.0300
N2	0.0000	0.0500	0.0000	0.0000	0.0200	0.0200
C1	0.4000	7.9800	0.5900	0.2600	3.1300	2.9000
C2	1.6600	1.5600	0.4000	0.4800	0.7000	1.1000
C3	2.2300	2.8200	0.5500	0.8100	1.0700	1.7100
i-C4	1.1500	1.4300	0.4500	0.3600	0.8800	1.0700
n-C4	1.9500	2.4400	0.6300	1.1800	1.1100	1.1500
i-C5	2.8400	2.1200	0.4800	1.2900	1.0500	1.5000
n-C5	1.3600	2.0900	0.4500	2.0600	1.0000	1.2300
C6	3.0700	2.5400	1.0000	2.6800	1.5300	2.3300
C7	6.9000	6.3500	4.3100	6.5200	4.4300	6.0000
C8	7.6500	8.0300	4.9000	7.3900	5.8900	8.7700
C9	5.8200	3.5600	4.1700	4.8600	4.2200	6.3100
C10+	61.2100	54.9600	80.5100	68.2000	72.4400	60.3600
Benzene	0.1500	0.2000	0.0900	0.0200	0.3100	0.3800
Toluene	0.6100	0.6800	0.1100	0.0900	0.3800	1.0700
E-Benzene	0.0400	0.1100	0.0200	0.0500	0.0500	0.3100
Xylenes	0.7000	1.0600	0.8100	0.5400	0.5000	2.2000
n-C6	1.1400	1.9000	0.5100	2.9100	1.1200	1.5600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 76**	**Sample Tank No. 77**	**Sample Tank No. 78**	**Sample Tank No. 79**	**Sample Tank No. 80**	**Sample Tank No. 81**
E&P Tank Number	**Tank No. 30**	**Tank No. 31**	**Tank No. 32**	**Tank No. 33**	**Tank No. 34**	**Tank No. 35**
Total Emissions (tpy)	75.697	67.111	33.481	98.139	246.837	206.565
VOC Emissions (tpy)	48.997	21.176	9.640	41.538	186.576	136.694
Methane Emissions (tpy)	15.026	39.198	18.906	45.393	13.777	5.258
HAP Emissions (tpy)	**1.330**	**0.460**	**0.290**	**1.230**	**7.150**	**4.120**
Benzene	*0.115*	*0.055*	*0.025*	*0.118*	*1.477*	*0.060*
Toluene	*0.088*	*0.025*	*0.040*	*0.085*	*1.336*	*0.122*
E-Benzene	*0.010*	*0.002*	*0.004*	*0.008*	*0.030*	*0.010*
Xylenes	*0.038*	*0.011*	*0.023*	*0.165*	*0.263*	*0.100*
n-C6	*1.075*	*0.362*	*0.196*	*0.852*	*4.047*	*3.833*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	20	60	18	40	18	15
Separator Temperature (F)	115	78	70	110	80	108
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	115	78	70	110	80	108
C10+ SG	0.885	0.866	0.875	0.87	0.923	0.887
C10+ MW	280	324	277	297	346	272
API Gravity	**33.0**	**34.0**	**34.0**	**34.0**	**35.0**	**35.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.10	2.00	2.20	3.20	4.70	4.50
GOR (scf/bbl)	8.96	12.60	6.20	16.18	24.36	18.78
Heating Value of Vapor (Btu/s	1989.27	1308.40	1280.62	1473.81	2361.43	2135.62
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0100	0.0500
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0300	0.0500	0.0700	0.0400	0.0600	0.6100
N2	0.0000	0.0000	0.0000	0.0100	0.0100	0.0500
C1	0.8400	2.8100	1.1600	2.9100	0.6400	0.2600
C2	0.3700	0.3100	0.2400	0.4400	1.0500	0.7800
C3	0.9200	0.6200	0.4900	0.6800	2.2200	1.7400
i-C4	1.0000	0.4700	0.4300	0.5800	0.8300	0.8400
n-C4	1.3200	0.7300	0.6500	0.6300	2.7600	2.3700
i-C5	1.3500	0.7100	0.8000	0.5300	2.1100	2.2400
n-C5	1.2200	0.6600	0.7000	0.4900	3.1100	2.2500
C6	1.8500	1.0800	1.2900	0.8900	3.5800	3.1500
C7	4.6800	2.3500	3.6200	4.6300	11.4200	6.1800
C8	5.5400	2.9600	5.5500	5.3100	11.2400	6.7100
C9	3.8000	1.9300	3.8000	4.5800	8.3200	5.0700
C10+	74.8700	84.1900	78.1200	76.3800	40.2000	64.3300
Benzene	0.1700	0.1100	0.1400	0.1000	1.6600	0.0500
Toluene	0.3400	0.1500	0.6900	0.1900	4.4100	0.2700
E-Benzene	0.0900	0.0300	0.1800	0.0400	0.2500	0.0500
Xylenes	0.3900	0.2000	1.2000	0.9800	2.5500	0.5900
n-C6	1.2200	0.6400	0.8700	0.5900	3.5700	2.4100
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 82**	**Sample Tank No. 83**	**Sample Tank No. 84**	**Sample Tank No. 85**	**Sample Tank No. 86**	**Sample Tank No. 87**
E&P Tank Number	**Tank No. 36**	**Tank No. 37**	**Tank No. 38**	**Tank No. 39**	**Tank No. 40**	**Tank No. 41**
Total Emissions (tpy)	176.370	34.019	82.578	113.253	204.693	178.190
VOC Emissions (tpy)	121.493	16.601	32.683	56.649	107.904	100.629
Methane Emissions (tpy)	10.526	12.380	40.189	30.738	57.039	28.323
HAP Emissions (tpy)	**3.520**	**1.050**	**1.820**	**2.310**	**3.540**	**2.460**
Benzene	*0.068*	*0.262*	*0.364*	*0.285*	*0.530*	*0.307*
Toluene	*0.092*	*0.297*	*0.293*	*0.292*	*0.386*	*0.280*
E-Benzene	*0.019*	*0.011*	*0.016*	*0.018*	*0.030*	*0.012*
Xylenes	*0.072*	*0.048*	*0.125*	*0.138*	*0.208*	*0.068*
n-C6	*3.266*	*0.435*	*1.023*	*1.573*	*2.383*	*1.789*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	17	30	50	57	75	28
Separator Temperature (F)	100	125	68	80	81	60
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	100	125	68	80	81	60
C10+ SG	0.887	0.863	0.879	0.883	0.883	0.891
C10+ MW	283	276	356	294	288	277
API Gravity	**35.0**	**36.0**	**36.0**	**36.0**	**36.0**	**36.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	2.50	3.80	3.90	4.10	3.80
GOR (scf/bbl)	17.62	5.02	14.02	15.52	27.84	22.04
Heating Value of Vapor (Btu/s	2307.25	1616.36	1437.32	1721.01	1718.90	1846.39
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.2000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.0300	0.0300	0.0600	0.1400	0.0600
N2	0.0100	0.0000	0.0100	0.0100	0.0100	0.0100
C1	0.5300	0.9100	2.4200	1.5900	2.9000	1.3300
C2	1.1100	0.3200	0.4500	0.7200	0.9500	0.9300
C3	1.7600	0.5700	0.8100	1.1100	1.4500	1.7200
i-C4	0.8000	0.3900	0.5400	0.7700	1.0000	0.4400
n-C4	2.3800	0.5800	1.1700	1.6000	1.8400	1.9800
i-C5	2.1600	0.6500	1.3400	1.5200	1.6700	1.2300
n-C5	2.6700	0.5700	1.6000	1.6700	1.7900	2.2100
C6	3.3700	1.0700	2.4800	2.5900	2.1500	2.4300
C7	6.0700	3.3600	7.6400	7.1400	6.1000	9.4100
C8	6.8700	5.7300	10.3500	9.7000	7.9700	10.5500
C9	6.0400	4.2600	5.9100	5.1000	5.2600	6.0500
C10+	62.5300	77.9200	57.3100	59.8700	61.4100	54.5600
Benzene	0.0700	0.5500	0.8300	0.5000	0.5100	0.6300
Toluene	0.2600	1.5800	2.0500	1.5100	1.0900	1.8200
E-Benzene	0.1300	0.1300	0.2900	0.2400	0.2200	0.2100
Xylenes	0.5600	0.6500	2.6900	2.1000	1.7300	1.4100
n-C6	2.5900	0.7300	2.0800	2.2000	1.8100	2.8200
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 88**	**Sample Tank No. 89**	**Sample Tank No. 90**	**Sample Tank No. 91**	**Sample Tank No. 92**	**Sample Tank No. 93**
E&P Tank Number	**Tank No. 42**	**Tank No. 43**	**Tank No. 44**	**Tank No. 45**	**Tank No. 46**	**Tank No. 47**
Total Emissions (tpy)	264.744	77.810	341.571	746.422	120.452	114.826
VOC Emissions (tpy)	197.667	45.796	126.289	598.797	71.033	53.659
Methane Emissions (tpy)	4.156	20.047	121.935	12.450	24.855	41.873
HAP Emissions (tpy)	**5.070**	**1.720**	**2.060**	**7.990**	**1.310**	**1.960**
Benzene	*0.536*	*0.269*	*0.294*	*3.587*	*0.126*	*0.496*
Toluene	*6.120*	*0.232*	*0.161*	*0.449*	*0.199*	*0.291*
E-Benzene	*0.040*	*0.014*	*0.036*	*0.061*	*0.009*	*0.009*
Xylenes	*0.205*	*0.121*	*0.106*	*0.072*	*0.077*	*0.052*
n-C6	*3.677*	*1.081*	*1.462*	*3.820*	*0.900*	*1.109*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	18	18	190	22	24	60
Separator Temperature (F)	95	98	70	50	68	72
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	95	98	70	50	68	72
C10+ SG	0.9	0.871	0.861	0.918	0.872	0.863
C10+ MW	288	270	270	372	239	318
API Gravity	**36.0**	**37.0**	**37.0**	**37.0**	**38.0**	**38.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	7.20	3.90	3.00	4.90	3.60	4.50
GOR (scf/bbl)	23.68	10.02	53.74	67.22	15.46	17.44
Heating Value of Vapor (Btu/s	2352.89	1820.80	1489.35	2491.03	1867.10	1590.85
LP Oil Component						
H2S	0.8700	0.0000	0.0000	0.1400	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1200	0.0500	0.3100	0.5300	0.0200	0.0500
N2	0.0200	0.0000	0.0300	0.0000	0.0000	0.0000
C1	0.1900	1.0400	6.2500	0.5600	1.1400	2.5500
C2	0.6800	0.4200	2.2000	2.3100	0.5800	0.8600
C3	2.5400	0.9700	2.0200	4.1000	1.2600	1.3500
i-C4	1.1400	1.1500	0.5500	1.9100	0.9300	0.9700
n-C4	3.8100	1.3100	1.1800	5.0000	1.4400	1.3600
i-C5	2.9900	1.6600	0.8300	3.4000	1.6100	1.4200
n-C5	2.9100	1.2800	0.7100	3.5100	1.3900	1.3400
C6	3.7100	2.1200	1.3200	3.0200	2.3200	2.1100
C7	9.0500	5.2700	3.8300	13.2800	6.5000	5.5300
C8	7.1100	7.7200	6.7800	13.1300	8.7200	7.6500
C9	5.9500	4.7200	2.8000	5.9600	5.9100	5.6600
C10+	52.8400	67.1300	69.1900	36.1900	62.7500	64.2400
Benzene	0.4700	0.5000	0.1800	2.6100	0.3100	0.8400
Toluene	1.5000	1.1900	0.3000	1.0600	1.5000	1.4900
E-Benzene	0.2400	0.1800	0.1800	0.4000	0.1800	0.1200
Xylenes	1.4100	1.7200	0.6100	0.5500	1.7900	0.8100
n-C6	2.4500	1.5700	0.7300	2.3400	1.6500	1.6500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 94**	**Sample Tank No. 95**	**Sample Tank No. 96**	**Sample Tank No. 97**	**Sample Tank No. 98**	**Sample Tank No. 99**
E&P Tank Number	**Tank No. 48**	**Tank No. 49**	**Tank No. 50**	**Tank No. 51**	**Tank No. 52**	**Tank No. 53**
Total Emissions (tpy)	54.705	437.309	165.905	279.758	608.810	254.487
VOC Emissions (tpy)	37.588	181.269	149.208	103.605	571.582	161.927
Methane Emissions (tpy)	8.963	1.079	0.600	12.141	8.030	48.433
HAP Emissions (tpy)	**2.550**	**4.660**	**4.640**	**1.630**	**17.380**	**7.830**
Benzene	*0.263*	*0.041*	*0.202*	*0.453*	*0.424*	*2.228*
Toluene	*0.317*	*0.110*	*0.380*	*0.085*	*0.458*	*1.268*
E-Benzene	*0.024*	*0.053*	*0.035*	*0.015*	*0.025*	*0.039*
Xylenes	*0.218*	*0.149*	*0.168*	*0.017*	*0.441*	*0.399*
n-C6	*1.726*	*4.311*	*3.855*	*1.063*	*16.032*	*3.892*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	32	62	13	28	22	66
Separator Temperature (F)	149	80	113	45	114	89
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	149	80	113	45	114	89
C10+ SG	0.862	0.894	0.882	0.904	0.877	0.877
C10+ MW	251	310	294	294	337	282
API Gravity	**38.0**	**38.0**	**38.0**	**38.0**	**38.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	5.20	5.70	7.40	3.10	3.70
GOR (scf/bbl)	5.82	37.60	13.60	28.24	45.82	30.08
Heating Value of Vapor (Btu/s	2216.65	1206.29	2853.46	1313.43	3053.30	1945.58
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	4.1200	0.0100	2.0000	0.0400	0.1800
N2	0.0000	0.0200	0.0000	0.0000	0.2000	0.0000
C1	0.5100	0.0500	0.0300	0.5300	0.4200	2.2600
C2	0.4400	0.3200	0.4500	1.0400	0.5700	0.8400
C3	0.5900	1.4800	2.4200	1.9800	2.1600	1.4800
i-C4	0.5400	0.8700	1.1900	1.4200	1.1400	1.0300
n-C4	0.6500	3.3500	3.2300	3.7800	4.2600	1.6000
i-C5	1.3500	3.0800	2.0600	2.9700	2.9000	2.0600
n-C5	1.1500	2.8200	3.0500	2.9500	4.2900	1.8600
C6	2.5000	4.7100	2.3400	2.6800	3.5200	3.4100
C7	6.4600	10.0400	7.7900	11.8900	10.3400	8.6400
C8	8.5600	11.8100	8.3700	11.7900	9.9300	11.0300
C9	3.4500	6.4100	6.4400	6.6500	4.4300	5.1000
C10+	69.3200	46.8100	57.0400	45.6300	51.0200	51.2400
Benzene	0.3200	0.0300	0.2000	1.1100	0.1100	1.6600
Toluene	0.9100	0.2400	0.9900	0.7100	0.3100	2.6900
E-Benzene	0.1500	0.3000	0.2100	0.3600	0.0400	0.2100
Xylenes	1.4800	0.9700	1.1500	0.4800	0.7800	2.4200
n-C6	1.6100	2.5700	3.0300	2.0300	3.5400	2.2900
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 100**	**Sample Tank No. 101**	**Sample Tank No. 102**	**Sample Tank No. 103**
E&P Tank Number	**Tank No. 54**	**Tank No. 55**	**Tank No. 56**	**Tank No. 57**
Total Emissions (tpy)	173.095	363.718	391.465	274.631
VOC Emissions (tpy)	97.629	237.995	191.567	204.825
Methane Emissions (tpy)	52.151	56.163	3.830	22.453
HAP Emissions (tpy)	**4.410**	**2.820**	**5.090**	**19.640**
Benzene	*0.242*	*0.369*	*0.970*	*5.674*
Toluene	*0.281*	*0.045*	*0.836*	*4.267*
E-Benzene	*0.031*	*0.026*	*0.019*	*0.070*
Xylenes	*0.164*	*0.129*	*0.135*	*0.436*
n-C6	*3.689*	*2.253*	*3.127*	*9.194*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	60	33	42
Separator Temperature (F)	80	58	60	110
Ambient Pressure (psia)	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	58	60	110
C10+ SG	0.891	0.877	0.907	0.879
C10+ MW	265	309	295	283
API Gravity	**39.0**	**39.0**	**39.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500
Reid Vapor Pressure (psia)	5.60	6.80	6.40	5.40
GOR (scf/bbl)	23.36	43.14	36.04	26.60
Heating Value of Vapor (Btu/s	1766.66	2016.56	1509.76	2428.31
LP Oil Component				
H2S	0.0000	0.0000	0.1100	0.0000
O2	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0300	2.4000	0.0100
N2	0.0100	0.0100	0.0000	0.0000
C1	2.3200	2.6700	0.1600	1.0900
C2	0.7200	1.7300	0.7600	1.5000
C3	1.1900	3.6000	2.6400	2.1200
i-C4	0.8900	1.8800	0.9100	0.8400
n-C4	1.8300	3.2300	3.5800	2.2800
i-C5	2.3500	2.4900	2.6500	1.6400
n-C5	3.2400	2.1100	3.4400	2.5200
C6	3.9900	2.7200	3.7800	2.6100
C7	9.9400	8.1600	10.7700	9.7300
C8	11.5600	11.9800	11.8300	8.9300
C9	6.0600	4.9500	6.1900	5.8900
C10+	48.9900	50.3400	40.8600	47.7300
Benzene	0.3000	0.3800	1.2700	2.7500
Toluene	1.0300	0.1500	3.4900	5.3000
E-Benzene	0.2900	0.2400	0.2200	0.2000
Xylenes	1.7800	1.3700	1.8000	1.3900
n-C6	3.4600	1.9600	3.1400	3.4700
224Trimethylp	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000

Tank ID					**API > 40**		
E&P Tank Number		**Average**	**ratios to HAP**	**Ratio to VOC**	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	Total	785.812			8152.118	129.419	1530.229
VOC Emissions (tpy)	VOC	530.750	**33.837**		5678.554	43.734	1046.343
Methane Emissions (tpy)	Methane	116.167	**7.406**	**0.219**	1206.981	0.197	230.569
HAP Emissions (tpy)	**HAP**	**15.685**		**0.030**	**101.610**	**2.680**	**30.684**
Benzene							
Toluene							
E-Benzene							
Xylenes							
n-C6							
224Trimethylp							
Separator Pressure (psig)	Separator Pressure	126.451			870.000	13.000	231.870
Separator Temperature (F)	Separator Temperature	88.657			140.000	40.000	82.500
Ambient Pressure (psia)							
Ambient Temperature (F)							
C10+ SG		0.893			0.929	0.801	0.873
C10+ MW		292.72			375.000	162.000	241.304
API Gravity	**API Gravity**	**40.6**			**68.0**	**40.0**	**52.8**
Production Rate (bbl/day)							
Reid Vapor Pressure (psia)	RVP	5.691			13.100	3.000	7.983
GOR (scf/bbl)	GOR	88.149			924.960	12.300	172.479
Heating Value of Vapor (Btu/s	Heating value	1968.085					
LP Oil Component		**Composition**					
H2S		0.0679					
O2		0.0000					
CO2		0.3661					
N2		0.0360					
C1		2.9248					
C2		1.6262					
C3		2.7564					
i-C4		1.3958					
n-C4		2.9738					
i-C5		2.4711					
n-C5		2.7194					
C6		3.2723					
C7		8.5230					
C8		10.3202					
C9		5.6686					
C10+		48.1339					
Benzene		0.6044					
Toluene		1.6882					
E-Benzene		0.1797					
Xylenes		1.4353					
n-C6		2.8369					
224Trimethylp		0.0000					
		100.0000					

Tank ID	**API <40**		
E&P Tank Number	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	746.422	13.397	174.327
VOC Emissions (tpy)	598.797	3.087	107.227
Methane Emissions (tpy)	124.465	0.115	22.193
HAP Emissions (tpy)	**19.640**	**0.070**	**3.366**
Benzene	5.674	0.003	0.445
Toluene	6.120	0.003	0.431
E-Benzene	0.086	0.000	0.019
Xylenes	0.732	0.001	0.120
n-C6	16.032	0.052	2.449
224Trimethylp	0.000	0.000	0.000
Separator Pressure (psig)	280.000	4.000	39.857
Separator Temperature (F)			
Ambient Pressure (psia)			
Ambient Temperature (F)			
C10+ SG	0.984	0.861	0.910
C10+ MW	551.000	239.000	334.946
API Gravity	**39.0**	**15.0**	**30.6**
Production Rate (bbl/day)			
Reid Vapor Pressure (psia)	7.400	0.600	3.809
GOR (scf/bbl)	67.220	2.340	18.878
Heating Value of Vapor (Btu/s			
LP Oil Component			
H2S			
O2			
CO2			
N2			
C1			
C2			
C3			
i-C4			
n-C4			
i-C5			
n-C5			
C6			
C7			
C8			
C9			
C10+			
Benzene			
Toluene			
E-Benzene			
Xylenes			
n-C6			
224Trimethylp			

API Gravity >40

	VOC Emissions (tpy)
Mean	1046.343
Standard Error	188.1410357
Median	530.989
Mode	#N/A
Standard Deviation	1276.034588
Sample Variance	1628264.269
Kurtosis	3.35522263
Skewness	1.864492873
Range	5634.82
Minimum	43.734
Maximum	5678.554
Sum	48131.778
Count	46
Largest(1)	5678.554
Confidence Level(95.0%)	378.9354921

	667.4075079
VOC	1046.343
	1425.278492

API Gravity <40

	VOC Emissions (tpy)
Mean	107.2265
Standard Error	15.51304
Median	72.87
Mode	#N/A
Standard Deviation	116.0889
Sample Variance	13476.64
Kurtosis	9.02191
Skewness	2.680349
Range	595.71
Minimum	3.087
Maximum	598.797
Sum	6004.685
Count	56
Largest(1)	598.797
Confidence Level(95.0%)	31.08882

	76.1377
VOC	107.2265
	138.3153

United States
Environmental Protection
Agency

Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, NC

EPA-453/R-11-002
July 2011

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Anthropogenic and Natural Radiative Forcing

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This chapter should be cited as:
Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

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Frequently Asked Questions

Supplementary Material

Supplementary Material is available in online versions of the report.

Executive Summary

It is unequivocal that anthropogenic increases in the well-mixed greenhouse gases (WMGHGs) have substantially enhanced the greenhouse effect, and the resulting forcing continues to increase. Aerosols partially offset the forcing of the WMGHGs and dominate the uncertainty associated with the total anthropogenic driving of climate change.

As in previous IPCC assessments, AR5 uses the radiative forcing[1] (RF) concept, but it also introduces effective radiative forcing[2] (ERF). The RF concept has been used for many years and in previous IPCC assessments for evaluating and comparing the strength of the various mechanisms affecting the Earth's radiation balance and thus causing climate change. Whereas in the RF concept all surface and tropospheric conditions are kept fixed, the ERF calculations presented here allow all physical variables to respond to perturbations except for those concerning the ocean and sea ice. The inclusion of these adjustments makes ERF a better indicator of the eventual temperature response. ERF and RF values are significantly different for anthropogenic aerosols owing to their influence on clouds and on snow cover. These changes to clouds are rapid adjustments and occur on a time scale much faster than responses of the ocean (even the upper layer) to forcing. RF and ERF are estimated over the Industrial Era from 1750 to 2011 if other periods are not explicitly stated. {8.1, Box 8.1, Figure 8.1}

Industrial-Era Anthropogenic Forcing

The total anthropogenic ERF over the Industrial Era is 2.3 (1.1 to 3.3) W m^{-2}.[3] It is certain that the total anthropogenic ERF is positive. Total anthropogenic ERF has increased more rapidly since 1970 than during prior decades. The total anthropogenic ERF estimate for 2011 is 43% higher compared to the AR4 RF estimate for the year 2005 owing to reductions in estimated forcing due to aerosols but also to continued growth in greenhouse gas RF. {8.5.1, Figures 8.15, 8.16}

Due to increased concentrations, RF from WMGHGs has increased by 0.20 (0.18 to 0.22) W m^{-2} (8%) since the AR4 estimate for the year 2005. The RF of WMGHG is 2.83 (2.54 to 3.12) W m^{-2}. The majority of this change since AR4 is due to increases in the carbon dioxide (CO_2) RF of nearly 10%. The Industrial Era RF for CO_2 alone is 1.82 (1.63 to 2.01) W m^{-2}, and CO_2 is the component with the largest global mean RF. Over the last decade RF of CO_2 has an average growth rate of 0.27 (0.24 to 0.30) W m^{-2} per decade. Emissions of CO_2 have made the largest contribution to the increased anthropogenic forcing in every decade since the 1960s. The best estimate for ERF of WMGHG is the same as the RF but with a larger uncertainty (±20%). {8.3.2, 8.5.2, Figures 8.6, 8.18}

The net forcing by WMGHGs other than CO_2 shows a small increase since the AR4 estimate for the year 2005. A small growth in the CH_4 concentration has increased its RF by 2% to an AR5 value of 0.48 (0.43 to 0.53) W m^{-2}. RF of nitrous oxide (N_2O) has increased by 6% since AR4 and is now 0.17 (0.14 to 0.20) W m^{-2}. N_2O concentrations continue to rise while those of dichlorodifluoromethane (CFC-12), the third largest WMGHG contributor to RF for several decades, is falling due to its phase-out under the Montreal Protocol and amendments. Since 2011 N_2O has become the third largest WMGHG contributor to RF. The RF from all halocarbons (0.36 W m^{-2}) is very similar to the value in AR4, with a reduced RF from chlorofluorocarbons (CFCs) but increases from many of their substitutes. Four of the halocarbons (trichlorofluoromethane (CFC-11), CFC-12, trichlorotrifluoroethane (CFC-113) and chlorodifluoromethane (HCFC-22)) account for around 85% of the total halocarbon RF. The first three of these compounds have declining RF over the last 5 years but their combined decrease is compensated for by the increased RF from HCFC-22. Since AR4, the RF from all HFCs has nearly doubled but still only amounts to 0.02 W m^{-2}. There is *high confidence*[4] that the overall growth rate in RF from all WMGHG is smaller over the last decade than in the 1970s and 1980s owing to a reduced rate of increase in the combined non-CO_2 RF. {8.3.2; Figure 8.6}

Ozone and stratospheric water vapour contribute substantially to RF. The total RF estimated from modelled ozone changes is 0.35 (0.15 to 0.55) W m^{-2}, with RF due to tropospheric ozone changes of 0.40 (0.20 to 0.60) W m^{-2} and due to stratospheric ozone changes of –0.05 (–0.15 to +0.05) W m^{-2}. Ozone is not emitted directly into the atmosphere but is formed by photochemical reactions. Tropospheric ozone RF is largely attributed to anthropogenic emissions of methane (CH_4), nitrogen oxides (NO_x), carbon monoxide (CO) and non-methane volatile organic compounds (NMVOCs), while stratospheric ozone RF results primarily from ozone depletion by halocarbons. Estimates are also provided attributing RF to emitted compounds. Ozone-depleting substances (ODS) cause ozone RF of –0.15 (–0.30 to 0.0) W m^{-2}, some of which is in the troposphere. Tropospheric ozone precursors cause ozone RF of 0.50 (0.30 to 0.70) W m^{-2}, some of which is in the stratosphere; this value is larger than that in AR4. There is *robust evidence* that tropospheric ozone also has a detrimental impact on vegetation physiology, and therefore on its CO_2 uptake, but there is a *low confidence* on quantitative estimates of the RF owing to this indirect effect. RF for stratospheric water vapour produced by CH_4 oxidation is 0.07 (0.02 to 0.12) W m^{-2}. The RF best estimates for ozone and stratospheric

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[1] Change in net downward radiative flux at the tropopause after allowing for stratospheric temperatures to readjust to radiative equilibrium, while holding surface and tropospheric temperatures and state variables fixed at the unperturbed values.

[2] Change in net downward radiative flux at the top of the atmosphere (TOA) after allowing for atmospheric temperatures, water vapour, clouds and land albedo to adjust, but with global mean surface temperature or ocean and sea ice conditions unchanged (calculations presented in this chapter use the fixed ocean conditions method).

[3] Uncertainties are given associated with best estimates of forcing. The uncertainty values represent the 5–95% (90%) confidence range.

[4] In this Report, the following summary terms are used to describe the available evidence: limited, medium, or robust; and for the degree of agreement: low, medium, or high. A level of confidence is expressed using five qualifiers: very low, low, medium, high, and very high, and typeset in italics, e.g., *medium confidence*. For a given evidence and agreement statement, different confidence levels can be assigned, but increasing levels of evidence and degrees of agreement are correlated with increasing confidence (see Section 1.4 and Box TS.1 for more details).

water vapour are either identical or consistent with the range in AR4. {8.2, 8.3.3, Figure 8.7}

The magnitude of the aerosol forcing is reduced relative to AR4. The RF due to aerosol–radiation interactions, sometimes referred to as *direct aerosol effect*, is given a best estimate of –0.35 (–0.85 to +0.15) W m^{-2}, and black carbon (BC) on snow and ice is 0.04 (0.02 to 0.09) W m^{-2}. The ERF due to aerosol–radiation interactions is –0.45 (–0.95 to +0.05) W m^{-2}. A total aerosol–cloud interaction[5] is quantified in terms of the ERF concept with an estimate of –0.45 (–1.2 to 0.0) W m^{-2}. The total aerosol effect (excluding BC on snow and ice) is estimated as ERF of –0.9 (–1.9 to –0.1) W m^{-2}. The large uncertainty in aerosol ERF is the dominant contributor to overall net Industrial Era forcing uncertainty. Since AR4, more aerosol processes have been included in models, and differences between models and observations persist, resulting in similar uncertainty in the aerosol forcing as in AR4. Despite the large uncertainty range, there is a *high confidence* that aerosols have offset a substantial portion of WMGHG global mean forcing. {8.3.4, 8.5.1, Figures 8.15, 8.16}

There is *robust evidence* that anthropogenic land use change has increased the land surface albedo, which leads to an RF of –0.15 ± 0.10 W m^{-2}. There is still a large spread of estimates owing to different assumptions for the albedo of natural and managed surfaces and the fraction of land use changes before 1750. Land use change causes additional modifications that are not radiative, but impact the surface temperature, in particular through the hydrologic cycle. These are more uncertain and they are difficult to quantify, but tend to offset the impact of albedo changes. As a consequence, there is *low agreement* on the sign of the net change in global mean temperature as a result of land use change. {8.3.5}

Attributing forcing to emissions provides a more direct link from human activities to forcing. The RF attributed to methane emissions is *very likely*[6] to be much larger (~1.0 W m^{-2}) than that attributed to methane *concentration* increases (~0.5 W m^{-2}) as concentration changes result from the partially offsetting impact of emissions of multiple species and subsequent chemical reactions. In addition, emissions of CO are *virtually certain* to have had a positive RF, while emissions of NO_X are *likely* to have had a net negative RF at the global scale. Emissions of ozone-depleting halocarbons are *very likely* to have caused a net positive RF as their own positive RF has outweighed the negative RF from the stratospheric ozone depletion that they have induced. {8.3.3, 8.5.1, Figure 8.17, FAQ 8.2}

Forcing agents such as aerosols, ozone and land albedo changes are highly heterogeneous spatially and temporally. These patterns generally track economic development; strong negative aerosol forcing appeared in eastern North America and Europe during the early 20th century, extending to Asia, South America and central Africa by 1980. Emission controls have since reduced aerosol pollution in North America and Europe, but not in much of Asia. Ozone forcing increased throughout the 20th century, with peak positive amplitudes around 15°N to 30°N due to tropospheric pollution but negative values over Antarctica due to stratospheric loss late in the century. The pattern and spatial gradients of forcing affect global and regional temperature responses as well as other aspects of climate response such as the hydrologic cycle. {8.6.2, Figure 8.25}

Natural Forcing

Satellite observations of total solar irradiance (TSI) changes from 1978 to 2011 show that the most recent solar cycle minimum was lower than the prior two. This *very likely* led to a small negative RF of –0.04 (–0.08 to 0.00) W m^{-2} between 1986 and 2008. The best estimate of RF due to TSI changes representative for the 1750 to 2011 period is 0.05 (to 0.10) W m^{-2}. This is substantially smaller than the AR4 estimate due to the addition of the latest solar cycle and inconsistencies in how solar RF has been estimated in earlier IPCC assessments. There is *very low confidence* concerning future solar forcing estimates, but there is *high confidence* that the TSI RF variations will be much smaller than the projected increased forcing due to GHG during the forthcoming decades. {8.4.1, Figures 8.10, 8.11}

The RF of volcanic aerosols is well understood and is greatest for a short period (~2 years) following volcanic eruptions. There have been no major volcanic eruptions since Mt Pinatubo in 1991, but several smaller eruptions have caused a RF for the years 2008–2011 of –0.11 (–0.15 to –0.08) W m^{-2} as compared to 1750 and –0.06 (–0.08 to –0.04) W m^{-2} as compared to 1999–2002. Emissions of CO_2 from volcanic eruptions since 1750 have been at least 100 times smaller than anthropogenic emissions. {8.4.2, 8.5.2, Figures 8.12, 8.13, 8.18}

There is *very high confidence* that industrial-era natural forcing is a small fraction of the anthropogenic forcing except for brief periods following large volcanic eruptions. In particular, *robust evidence* from satellite observations of the solar irradiance and volcanic aerosols demonstrates a near-zero (–0.1 to +0.1 W m^{-2}) change in the natural forcing compared to the anthropogenic ERF increase of 1.0 (0.7 to 1.3) W m^{-2} from 1980 to 2011. The natural forcing over the last 15 years has *likely* offset a substantial fraction (at least 30%) of the anthropogenic forcing. {8.5.2; Figures 8.18, 8.19, 8.20}

Future Anthropogenic Forcing and Emission Metrics

Differences in RF between the emission scenarios considered here[7] are relatively small for year 2030 but become very large by 2100 and are dominated by CO_2. The scenarios show a substantial

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[5] The aerosol–cloud interaction represents the portion of rapid adjustments to aerosols initiated by aerosol-cloud interactions, and is defined here as the total aerosol ERF minus the ERF due to aerosol-radiation-interactions (the latter includes cloud responses to the aerosol–radiation interaction RF)

[6] In this Report, the following terms have been used to indicate the assessed likelihood of an outcome or a result: Virtually certain 99–100% probability, Very likely 90–100%, Likely 66–100%, About as likely as not 33–66%, Unlikely 0–33%, Very unlikely 0–10%, Exceptionally unlikely 0–1%. Additional terms (Extremely likely: 95–100%, More likely than not >50–100%, and Extremely unlikely 0–5%) may also be used when appropriate. Assessed likelihood is typeset in italics, e.g., *very likely* (see Section 1.4 and Box TS.1 for more details).

[7] Chapter 1 describes the Representative Concentration Pathways (RCPs) that are the primary scenarios discussed in this report.

weakening of the negative total aerosol ERF. Nitrate aerosols are an exception to this reduction, with a substantial increase, which is a robust feature among the few available models for these scenarios. The scenarios emphasized in this assessment do not span the range of future emissions in the literature, however, particularly for near-term climate forcers. {8.2.2, 8.5.3, Figures 8.2, 8.21, 8.22}

Emission metrics such as Global Warming Potential (GWP) and Global Temperature change Potential (GTP) can be used to quantify and communicate the relative and absolute contributions to climate change of emissions of different substances, and of emissions from regions/countries or sources/sectors. The metric that has been used in policies is the GWP, which integrates the RF of a substance over a chosen time horizon, relative to that of CO_2. The GTP is the ratio of change in global mean surface temperature at a chosen point in time from the substance of interest relative to that from CO_2. There are significant uncertainties related to both GWP and GTP, and the relative uncertainties are larger for GTP. There are also limitations and inconsistencies related to their treatment of indirect effects and feedbacks. The values are very dependent on metric type and time horizon. The choice of metric and time horizon depends on the particular application and which aspects of climate change are considered relevant in a given context. Metrics do not define policies or goals but facilitate evaluation and implementation of multi-component policies to meet particular goals. All choices of metric contain implicit value-related judgements such as type of effect considered and weighting of effects over time. This assessment provides updated values of both GWP and GTP for many compounds. {8.7.1, 8.7.2, Table 8.7, Table 8.A.1, Supplementary Material Table 8.SM.16}

Forcing and temperature response can also be attributed to sectors. From this perspective and with the GTP metric, a single year's worth of current global emissions from the energy and industrial sectors have the largest contributions to global mean warming over the next approximately 50 to 100 years. Household fossil fuel and biofuel, biomass burning and on-road transportation are also relatively large contributors to warming over these time scales, while current emissions from sectors that emit large amounts of CH_4 (animal husbandry, waste/landfills and agriculture) are also important over shorter time horizons (up to 20 years). {8.7.2, Figure 8.34}

8.1 Radiative Forcing

There are a variety of ways to examine how various drivers contribute to climate change. In principle, observations of the climate response to a single factor could directly show the impact of that factor, or climate models could be used to study the impact of any single factor. In practice, however, it is usually difficult to find measurements that are influenced by only a single cause, and it is computationally prohibitive to simulate the response to every individual factor of interest. Hence various metrics intermediate between cause and effect are used to provide estimates of the climate impact of individual factors, with applications both in science and policy. Radiative forcing (RF) is one of the most widely used metrics, with most other metrics based on RF. In this chapter, we discuss RF from natural and anthropogenic components during the industrial period, presenting values for 2011 relative to 1750 unless otherwise stated, and projected values through 2100 (see also Annex II). In this section, we present the various definitions of RF used in this chapter, and discuss the utility and limitations of RF. These definitions are used in the subsequent sections quantifying the RF due to specific anthropogenic (Section 8.3) and natural (Section 8.4) causes and integrating RF due to all causes (Sections 8.5 and 8.6). Atmospheric chemistry relevant for RF is discussed in Section 8.2 and used throughout the chapter. Emission metrics using RF that are designed to facilitate rapid evaluation and comparison of the climate effects of emissions are discussed in Section 8.7.

8.1.1 The Radiative Forcing Concept

RF is the net change in the energy balance of the Earth system due to some imposed perturbation. It is usually expressed in watts per square meter averaged over a particular period of time and quantifies the energy imbalance that occurs when the imposed change takes place. Though usually difficult to observe, calculated RF provides a simple quantitative basis for comparing some aspects of the potential climate response to different imposed agents, especially global mean temperature, and hence is widely used in the scientific community. Forcing is often presented as the value due to changes between two particular times, such as pre-industrial to present-day, while its time evolution provides a more complete picture.

8.1.1.1 Defining Radiative Forcing

Alternative definitions of RF have been developed, each with its own advantages and limitations. The instantaneous RF refers to an instantaneous change in net (down minus up) radiative flux (shortwave plus longwave; in W m^{-2}) due to an imposed change. This forcing is usually defined in terms of flux changes at the top of the atmosphere (TOA) or at the climatological tropopause, with the latter being a better indicator of the global mean surface temperature response in cases when they differ.

Climate change takes place when the system responds in order to counteract the flux changes, and all such responses are explicitly excluded from this definition of forcing. The assumed relation between a sustained RF and the equilibrium global mean surface temperature response (ΔT) is $\Delta T = \lambda \mathrm{RF}$ where λ is the climate sensitivity parameter. The relationship between RF and ΔT is an expression of the energy balance of the climate system and a simple reminder that the steady-state global mean climate response to a given forcing is determined both by the forcing and the responses inherent in λ.

Implicit in the concept of RF is the proposition that the change in net irradiance in response to the imposed forcing alone can be separated from all subsequent responses to the forcing. These are not in fact always clearly separable and thus some ambiguity exists in what may be considered a forcing versus what is part of the climate response.

In both the Third Assessment Report (TAR) and AR4, the term radiative forcing (RF, also called stratospherically adjusted RF, as distinct from instantaneous RF) was defined as the change in net irradiance at the tropopause after allowing for stratospheric temperatures to readjust to radiative equilibrium, while holding surface and tropospheric temperatures and state variables such as water vapour and cloud cover fixed at the unperturbed values[8]. RF is generally more indicative of the surface and tropospheric temperature responses than instantaneous RF, especially for agents such as carbon dioxide (CO_2) or ozone (O_3) change that substantially alter stratospheric temperatures. To be consistent with TAR and AR4, RF is hereafter taken to mean the stratospherically adjusted RF.

8.1.1.2 Defining Effective Radiative Forcing

For many forcing agents the RF gives a very useful and appropriate way to compare the relative importance of their potential climate effect. Instantaneous RF or RF is not an accurate indicator of the temperature response for all forcing agents, however. Rapid adjustments in the troposphere can either enhance or reduce the flux perturbations, leading to substantial differences in the forcing driving long-term climate change. In much the same way that allowing for the relatively rapid adjustment of stratospheric temperatures provides a more useful characterization of the forcing due to stratospheric constituent changes, inclusion of rapid tropospheric adjustments has the potential to provide more useful characterization for drivers in the troposphere (see also Section 7.1.3).

Many of the rapid adjustments affect clouds and are not readily included into the RF concept. For example, for aerosols, especially absorbing ones, changes in the temperature distribution above the surface occur due to a variety of effects, including cloud response to changing atmospheric stability (Hansen et al., 2005; see Section 7.3.4.2) and cloud absorption effects (Jacobson, 2012), which affect fluxes but are not strictly part of RF. Similar adjustments take place for many forcings, including CO_2 (see Section 7.2.5.6).

Aerosols also alter cloud properties via microphysical interactions leading to indirect forcings (referred to as aerosol–cloud interactions;

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[8] Tropospheric variables were fixed except for the impact of aerosols on cloud albedo due to changes in droplet size with constant cloud liquid water which was considered an RF in AR4 but is part of ERF in AR5.

see Section 7.4). Although these adjustments are complex and not fully quantified, they occur both on the microphysical scale of the cloud particles as well as on a more macroscopic scale involving whole cloud systems (e.g., Shine et al., 2003; Penner et al., 2006; Quaas et al., 2009). A portion of these adjustments occurs over a short period, on cloud life cycle time scales, and is not part of a feedback arising from the surface temperature changes. Previously these type of adjustments were sometimes termed 'fast feedbacks' (e.g., Gregory et al., 2004; Hansen et al., 2005), whereas in AR5 they are denoted 'rapid adjustments' to emphasize their distinction from feedbacks involving surface temperature changes. Atmospheric chemistry responses have typically been included under the RF framework, and hence could also be included in a forcing encompassing rapid adjustments, which is important when evaluating forcing attributable to emissions changes (Section 8.1.2) and in the calculation of emission metrics (Section 8.7).

Studies have demonstrated the utility of including rapid adjustment in comparison of forcing agents, especially in allowing quantification of forcing due to aerosol-induced changes in clouds (e.g., effects previously denoted as cloud lifetime or semi-direct effects; see Figure 7.3) that are not amenable to characterization by RF (e.g., Rotstayn and Penner, 2001; Shine et al., 2003; Hansen et al., 2005; Lohmann et al., 2010; Ban-Weiss et al., 2012). Several measures of forcing have been introduced that include rapid adjustments. We term a forcing that accounts for rapid adjustments the effective radiative forcing (ERF). Conceptually, ERF represents the change in net TOA downward radiative flux after allowing for atmospheric temperatures, water vapour and clouds to adjust, but with global mean surface temperature or a portion of surface conditions unchanged. The primary methods in use for such calculations are (1) fixing sea surface temperatures (SSTs) and sea ice cover at climatological values while allowing all other parts of the system to respond until reaching steady state (e.g., Hansen et al., 2005) or (2) analyzing the transient global mean surface temperature response to an instantaneous perturbation and using the regression of the response extrapolated back to the start of the simulation to derive the initial ERF (Gregory et al., 2004; Gregory and Webb, 2008). The ERF calculated using the regression technique has an uncertainty of about 10% (for the 5 to 95% confidence interval) for a single 4 × CO_2 simulation (ERF ~7 W m^{-2}) due to internal variability in the transient climate (Andrews et al., 2012a), while given a similar length simulation the uncertainty due to internal variability in ERF calculated using the fixed-SST technique is much smaller and hence the latter may be more suitable for very small forcings. Analysis of both techniques shows that the fixed-SST method yields a smaller spread across models, even in calculations neglecting the uncertainty in the regression fitting procedure (Andrews et al., 2012a). As a portion of land area responses are included in the fixed-SST technique, however, that ERF is slightly less than it would be with surface temperature held fixed everywhere. It is possible to adjust for this in the global mean forcing, though we do not include such a correction here as we examine regional as well as global ERF, but the land response will also introduce artificial gradients in land–sea temperatures that could cause small local climate responses. In contrast, there is no global mean temperature response included in the regression method. Despite the low bias in fixed-SST ERF due to land responses, results from a multi-model analysis of the forcing due to CO_2 are 7% greater using this method than using the regression technique (Andrews et al., 2012a) though this is within the uncertainty range of the calculations. Although each technique has advantages, forcing diagnosed using the fixed-SST method is available for many more forcing agents in the current generation of climate models than forcing diagnosed using the regression method. Hence for practical purposes, ERF is hereafter used for results from the fixed-SST technique unless otherwise stated (see also Box 8.1).

The conceptual relation between instantaneous RF, RF and ERF is illustrated in Figure 8.1. It implies the adjustments to the instantaneous RF involve effects of processes that occur more rapidly than the time scale of the response of the global mean surface temperature to the forcing. However, there is no *a priori* time scale defined for adjustments to be rapid with the fixed-SST method. The majority take place on time scales

Box 8.1 | Definition of Radiative Forcing and Effective Radiative Forcing

The two most commonly used measures of radiative forcing in this chapter are the radiative forcing (RF) and the effective radiative forcing (ERF). RF is defined, as it was in AR4, as the change in net downward radiative flux at the tropopause after allowing for stratospheric temperatures to readjust to radiative equilibrium, while holding surface and tropospheric temperatures and state variables such as water vapor and cloud cover fixed at the unperturbed values.

ERF is the change in net TOA downward radiative flux after allowing for atmospheric temperatures, water vapour and clouds to adjust, but with surface temperature or a portion of surface conditions unchanged. Although there are multiple methods to calculate ERF, we take ERF to mean the method in which sea surface temperatures and sea ice cover are fixed at climatological values unless otherwise specified. Land surface properties (temperature, snow and ice cover and vegetation) are allowed to adjust in this method. Hence ERF includes both the effects of the forcing agent itself and the rapid adjustments to that agent (as does RF, though stratospheric temperature is the only adjustment for the latter). In the case of aerosols, the rapid adjustments of clouds encompass effects that have been referred to as indirect or semi-direct forcings (see Figure 7.3 and Section 7.5), with some of these same cloud responses also taking place for other forcing agents (see Section 7.2). Calculation of ERF requires longer simulations with more complex models than calculation of RF, but the inclusion of the additional rapid adjustments makes ERF a better indicator of the eventual global mean temperature response, especially for aerosols. When forcing is attributed to emissions or used for calculation of emission metrics, additional responses including atmospheric chemistry and the carbon cycle are also included in both RF and ERF (see Section 8.1.2). The general term *forcing* is used to refer to both RF and ERF.

Frequently Asked Questions

FAQ 8.1 | How Important Is Water Vapour to Climate Change?

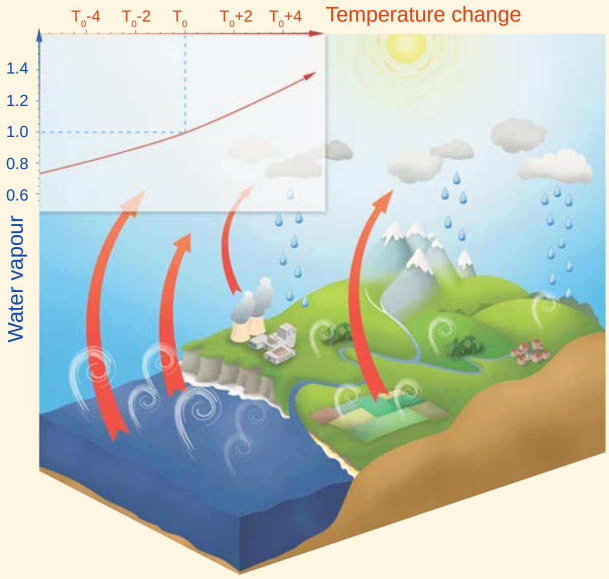
As the largest contributor to the natural greenhouse effect, water vapour plays an essential role in the Earth's climate. However, the amount of water vapour in the atmosphere is controlled mostly by air temperature, rather than by emissions. For that reason, scientists consider it a feedback agent, rather than a forcing to climate change. Anthropogenic emissions of water vapour through irrigation or power plant cooling have a negligible impact on the global climate.

Water vapour is the primary greenhouse gas in the Earth's atmosphere. The contribution of water vapour to the natural greenhouse effect relative to that of carbon dioxide (CO_2) depends on the accounting method, but can be considered to be approximately two to three times greater. Additional water vapour is injected into the atmosphere from anthropogenic activities, mostly through increased evaporation from irrigated crops, but also through power plant cooling, and marginally through the combustion of fossil fuel. One may therefore question why there is so much focus on CO_2, and not on water vapour, as a forcing to climate change.

Water vapour behaves differently from CO_2 in one fundamental way: it can condense and precipitate. When air with high humidity cools, some of the vapour condenses into water droplets or ice particles and precipitates. The typical residence time of water vapour in the atmosphere is ten days. The flux of water vapour into the atmosphere from anthropogenic sources is considerably less than from 'natural' evaporation. Therefore, it has a negligible impact on overall concentrations, and does not contribute significantly to the long-term greenhouse effect. This is the main reason why tropospheric water vapour (typically below 10 km altitude) is not considered to be an anthropogenic gas contributing to radiative forcing.

Anthropogenic emissions do have a significant impact on water vapour in the stratosphere, which is the part of the atmosphere above about 10 km. Increased concentrations of methane (CH_4) due to human activities lead to an additional source of water, through oxidation, which partly explains the observed changes in that atmospheric layer. That stratospheric water change has a radiative impact, is considered a forcing, and can be evaluated. Stratospheric concentrations of water have varied significantly in past decades. The full extent of these variations is not well understood and is probably less a forcing than a feedback process added to natural variability. The contribution of stratospheric water vapour to warming, both forcing and feedback, is much smaller than from CH_4 or CO_2.

The maximum amount of water vapour in the air is controlled by temperature. A typical column of air extending from the surface to the stratosphere in polar regions may contain only a few kilograms of water vapour per square metre, while a similar column of air in the tropics may contain up to 70 kg. With every extra degree of air temperature, the atmosphere can retain around 7% more water vapour (see upper-left insert in the FAQ 8.1, Figure 1). This increase in concentration amplifies the greenhouse effect, and therefore leads to more warming. This process, referred to as the water vapour feedback, is well understood and quantified. It occurs in all models used to estimate climate change, where its strength is consistent with observations. Although an increase in atmospheric water vapour has been observed, this change is recognized as a climate feedback (from increased atmospheric temperature) and should not be interpreted as a radiative forcing from anthropogenic emissions. *(continued on next page)*



FAQ 8.1, Figure 1 | Illustration of the water cycle and its interaction with the greenhouse effect. The upper-left insert indicates the relative increase of potential water vapour content in the air with an increase of temperature (roughly 7% per degree). The white curls illustrate evaporation, which is compensated by precipitation to close the water budget. The red arrows illustrate the outgoing infrared radiation that is partly absorbed by water vapour and other gases, a process that is one component of the greenhouse effect. The stratospheric processes are not included in this figure.

FAQ 8.1 (continued)

Currently, water vapour has the largest greenhouse effect in the Earth's atmosphere. However, other greenhouse gases, primarily CO_2, are necessary to sustain the presence of water vapour in the atmosphere. Indeed, if these other gases were removed from the atmosphere, its temperature would drop sufficiently to induce a decrease of water vapour, leading to a runaway drop of the greenhouse effect that would plunge the Earth into a frozen state. So greenhouse gases other than water vapour provide the temperature structure that sustains current levels of atmospheric water vapour. Therefore, although CO_2 is the main anthropogenic control knob on climate, water vapour is a strong and fast feedback that amplifies any initial forcing by a typical factor between two and three. Water vapour is not a significant initial forcing, but is nevertheless a fundamental agent of climate change.

of seasons or less, but there is a spectrum of adjustment times. Changes in land ice and snow cover, for instance, may take place over many years. The ERF thus represents that part of the instantaneous RF that is maintained over long time scales and more directly contributes to the steady-state climate response. The RF can be considered a more limited version of ERF. Because the atmospheric temperature has been allowed to adjust, ERF would be nearly identical if calculated at the tropopause instead of the TOA for tropospheric forcing agents, as would RF. Recent work has noted likely advantages of the ERF framework for understanding model responses to CO_2 as well as to more complex forcing agents (see Section 7.2.5.6).

The climate sensitivity parameter λ derived with respect to RF can vary substantially across different forcing agents (Forster et al., 2007). The response to RF from a particular agent relative to the response to RF from CO_2 has been termed the *efficacy* (Hansen et al., 2005). By including many of the rapid adjustments that differ across forcing agents, the ERF concept includes much of their relative efficacy and therefore leads to more uniform climate sensitivity across agents. For example, the influence of clouds on the interaction of aerosols with sunlight and the effect of aerosol heating on cloud formation can lead to very large differences in the response per unit RF from black carbon (BC) located at different altitudes, but the response per unit ERF is nearly uniform with altitude (Hansen et al., 2005; Ming et al., 2010; Ban-Weiss et al., 2012). Hence as we use ERF in this chapter when it differs significantly from RF, efficacy is not used hereinafter. For inhomogeneous forcings, we note that the climate sensitivity parameter may also depend on the horizontal forcing distribution, especially with latitude (Shindell and Faluvegi, 2009; Section 8.6.2).

A combination of RF and ERF will be used in this chapter with RF provided to keep consistency with TAR and AR4, and ERF used to allow quantification of more complex forcing agents and, in some cases, provide a more useful metric than RF.

8.1.1.3 Limitations of Radiative Forcing

Both the RF and ERF concepts have strengths and weaknesses in addition to those discussed previously. Dedicated climate model simulations that are required to diagnose the ERF can be more computationally demanding than those for instantaneous RF or RF because many years are required to reduce the influence of climate variability. The presence of meteorological variability can also make it difficult to isolate the ERF of small forcings that are easily isolated in the pair of radiative transfer calculations performed for RF (Figure 8.1). For RF, on the other hand, a definition of the tropopause is required, which can be ambiguous.

In many cases, however, ERF and RF are nearly equal. Analysis of 11 models from the current Coupled Model Intercomparison Project Phase 5 (CMIP5) generation finds that the rapid adjustments to CO_2 cause fixed-SST-based ERF to be 2% less than RF, with an intermodel standard deviation of 7% (Vial et al., 2013). This is consistent with an earlier study of six GCMs that found a substantial inter-model variation in the rapid tropospheric adjustment to CO_2 using regression analysis in slab ocean models, though the ensemble mean adjustment was less than 5% (Andrews and Forster, 2008). Part of the large uncertainty range arises from the greater noise inherent in regression analyses of single runs in comparison with fixed-SST experiments. Using fixed-SST simulations, Hansen et al. (2005) found that ERF is virtually identical to RF for increased CO_2, tropospheric ozone and solar irradiance, and within 6% for methane (CH_4), nitrous oxide (N_2O), stratospheric aerosols and for the aerosol–radiation interaction of reflective aerosols. Shindell et al. (2013b) also found that RF and ERF are statistically equal for tropospheric ozone. Lohmann et al. (2010) report a small increase in the forcing from CO_2 using ERF instead of RF based on the fixed-SST technique, while finding no substantial difference for CH_4, RF due to aerosol–radiation interactions or aerosol effects on cloud albedo. In the fixed-SST simulations of Hansen et al. (2005), ERF was about 20% less than RF for the atmospheric effects of BC aerosols (not including microphysical aerosol–cloud interactions), and nearly 300% greater for the forcing due to BC snow albedo forcing (Hansen et al., 2007). ERF was slightly greater than RF for stratospheric ozone in Hansen et al. (2005), but the opposite is true for more recent analyses (Shindell et al., 2013b), and hence it seems most appropriate at present to use RF for this small forcing. The various studies demonstrate that RF provides a good estimate of ERF in most cases, as the differences are very small, with the notable exceptions of BC-related forcings (Bond et al., 2013). ERF provides better characterization of those effects, as well as allowing quantification of a broader range of effects including all aerosol–cloud interactions. Hence while RF and ERF are generally quite similar for WMGHGs, ERF typically provides a more useful indication of climate response for near-term climate forcers (see Box 8.2). As the rapid adjustments included in ERF differ in strength across climate models, the uncertainty range for ERF estimates tends to be larger than the range for RF estimates.

Box 8.2 | Grouping Forcing Compounds by Common Properties

As many compounds cause RF when their atmospheric concentration is changed, it can be useful to refer to groups of compounds with similar properties. Here we discuss two primary groupings: well-mixed greenhouse gases (WMGHGs) and near-term climate forcers (NTCFs).

We define as 'well-mixed' those greenhouse gases that are sufficiently mixed throughout the troposphere that concentration measurements from a few remote surface sites can characterize the climate-relevant atmospheric burden; although these gases may still have local variation near sources and sinks and even small hemispheric gradients. Global forcing per unit emission and emission metrics for these gases thus do not depend on the geographic location of the emission, and forcing calculations can assume even horizontal distributions. These gases, or a subset of them, have sometimes been referred to as 'long-lived greenhouse gases' as they are well mixed because their atmospheric lifetimes are much greater than the time scale of a few years for atmospheric mixing, but the physical property that causes the aforementioned common characteristics is more directly associated with their mixing within the atmosphere. WMGHGs include CO_2, N_2O, CH_4, SF_6, and many halogenated species. Conversely, ozone is not a WMGHG.

We define 'near-term climate forcers' (NTCFs) as those compounds whose impact on climate occurs primarily within the first decade after their emission. This set of compounds is composed primarily of those with short lifetimes in the atmosphere compared to WMGHGs, and has been sometimes referred to as short-lived climate forcers or short-lived climate pollutants. However, the common property that is of greatest interest to a climate assessment is the time scale over which their impact on climate is felt. This set of compounds includes methane, which is also a WMGHG, as well as ozone and aerosols, or their precursors, and some halogenated species that are not WMGHGs. These compounds do not accumulate in the atmosphere at decadal to centennial time scales, and so their effect on climate is predominantly in the near term following their emission.

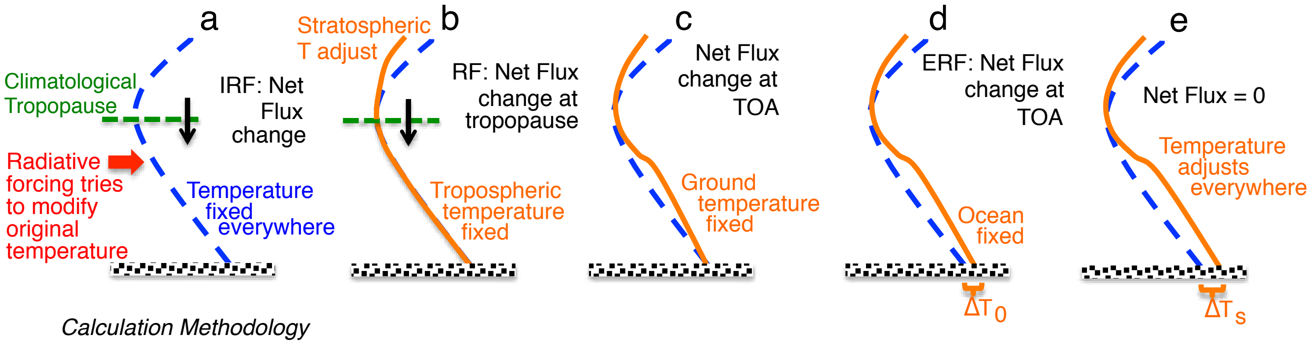
Whereas the global mean ERF provides a useful indication of the eventual change in global mean surface temperature, it does not reflect regional climate changes. This is true for all forcing agents, but is especially the case for the inhomogeneously distributed forcings because they activate climate feedbacks based on their regional distribution. For example, forcings over Northern Hemisphere (NH) middle and high latitudes induce snow and ice albedo feedbacks more than forcings at lower latitudes or in the Southern Hemisphere (SH) (e.g., Shindell and Faluvegi, 2009).

In the case of agents that strongly absorb incoming solar radiation (such as BC, and to a lesser extent organic carbon (OC) and ozone) the TOA forcing provides little indication of the change in solar radiation reaching the surface which can force local changes in evaporation and alter regional and general circulation patterns (e.g., Ramanathan and Carmichael, 2008; Wang et al., 2009). Hence the forcing at the surface, or the atmospheric heating, defined as the difference between surface and tropopause/TOA forcing, might also be useful metrics. Global mean precipitation changes can be related separately to ERF within the atmosphere and to a slower response to global mean temperature changes (Andrews et al., 2010; Ming et al., 2010; Ban-Weiss et al., 2012). Relationships between surface forcing and localized aspects of climate response have not yet been clearly quantified, however.

In general, most widely used definitions of forcing and most forcing-based metrics are intended to be proportional to the eventual temperature response, and most analyses to date have explored the global mean temperature response only. These metrics do not explicitly include impacts such as changes in precipitation, surface sunlight available for photosynthesis, extreme events, and so forth, or regional temperatures, which can differ greatly from the global mean. Hence although they are quite useful for understanding the factors driving global mean temperature change, they provide only an imperfect and limited perspective on the factors driving broader climate change. In addition, a metric based solely on radiative perturbations does not allow comparison of non-RFs, such as effects of land cover change on evapotranspiration or physiological impacts of CO_2 and O_3 except where these cause further impacts on radiation such as through cloud cover changes (e.g., Andrews et al., 2012b).

8.1.2 Calculation of Radiative Forcing due to Concentration or Emission Changes

Analysis of forcing due to observed or modelled concentration changes between pre-industrial, defined here as 1750, and a chosen later year provides an indication of the importance of different forcing agents to climate change during that period. Such analyses have been a mainstay of climate assessments. This perspective has the advantage that observational data are available to accurately quantify the concentration changes for several of the largest forcing components. Atmospheric concentration changes, however, are the net result of variations in emissions of multiple compounds and any climate changes that have influenced processes such as wet removal, atmospheric chemistry or the carbon cycle. Characterizing forcing according to *concentration* changes thus mixes multiple root causes along with climate feedbacks. Policy decisions are better informed by analysis of forcing attributable to *emissions*, which the IPCC first presented in AR4. These analyses can be applied to historical emissions changes in a 'backward-looking' perspective, as done for example, for major WMGHGs (den Elzen et al., 2005; Hohne et al., 2011) and NTCFs (Shindell et al., 2009), or to current



Calculation Methodology

a	b	c	d	e
Online or offline pair of radiative transfer calculations within one simulation	Difference between two offline radiative transfer calculations with prescribed surface and tropospheric conditions allowing stratospheric temperature to adjust	Difference between two full atmospheric model simulations with prescribed surface conditions everywhere or estimate based on regression of response in full coupled atmosphere-ocean simulation	Difference between two full atmospheric model simulations with prescribed ocean conditions (SSTs and sea ice)	Difference between two full coupled atmosphere-ocean model simulations

Figure 8.1 | Cartoon comparing (a) instantaneous RF, (b) RF, which allows stratospheric temperature to adjust, (c) flux change when the surface temperature is fixed over the whole Earth (a method of calculating ERF), (d) the ERF calculated allowing atmospheric and land temperature to adjust while ocean conditions are fixed and (e) the equilibrium response to the climate forcing agent. The methodology for calculation of each type of forcing is also outlined. ΔT_o represents the land temperature response, while ΔT_s is the full surface temperature response. (Updated from Hansen et al., 2005.)

or projected future emissions in a 'forward-looking' view (see Section 8.7). Emissions estimates through time typically come from the scientific community, often making use of national reporting for recent decades.

With the greater use of emission-driven models, for example, in CMIP5, it is becoming more natural to estimate ERF resulting from emissions of a particular species rather than concentration-based forcing. Such calculations typically necessitate model simulations with chemical transport models or chemistry–climate models, however, and require careful consideration of which processes are included, especially when comparing results to concentration-based forcings. In particular, simulation of concentration responses to emissions changes requires incorporating models of the carbon cycle and atmospheric chemistry (gas and aerosol phases). The requisite expansion of the modelling realm for emissions-based forcing or emission metrics should in principle be consistent for all drivers. For example, as the response to aerosol or ozone precursor emissions includes atmospheric chemistry, the response to CO_2 emissions should as well. In addition, if the CO_2 concentration responses to CO_2 emissions include the impact of CO_2-induced climate changes on carbon uptake, then the effect of climate changes caused by any other emission on carbon uptake should also be included. Similarly, if the effects of atmospheric CO_2 concentration change on carbon uptake are included, the effects of other atmospheric composition or deposition changes on carbon uptake should be included as well (see also Section 6.4.1). Comparable issues are present for other forcing agents. In practice, the modelling realm used in studies of forcing attributable to emissions has not always been consistent. Furthermore, climate feedbacks have sometimes been included in the calculation of forcing due to ozone or aerosol changes, as when concentrations from a historical transient climate simulation are imposed for an ERF calculation. In this chapter, we endeavour to clarify which processes have been included in the various estimates of forcing attributed to emissions (Sections 8.3 and 8.7).

RF or ERF estimates based on either historical emissions or concentrations provide valuable insight into the relative and absolute contribution of various drivers to historical climate change. Scenarios of changing future emissions and land use are also developed based on various assumptions about socioeconomic trends and societal choices. The forcing resulting from such scenarios is used to understand the drivers of potential future climate changes (Sections 8.5.3 and 8.6). As with historical forcings, the actual impact on climate depends on both the temporal and spatial structure of the forcings and the rate of response of various portions of the climate system.

8.2 Atmospheric Chemistry

8.2.1 Introduction

Most radiatively active compounds in the Earth's atmosphere are chemically active, meaning that atmospheric chemistry plays a large role in determining their burden and residence time. In the atmosphere, a gaseous chemically active compound can be affected by (1) interaction with other species (including aerosols and water) in its immediate vicinity and (2) interaction with solar radiation (photolysis). Physical processes (wet removal and dry deposition) act on some chemical compounds (gas or aerosols) to further define their residence time in the atmosphere. Atmospheric chemistry is characterized by many interactions and patterns of temporal or spatial variability, leading to significant nonlinearities (Kleinman et al., 2001) and a wide range of time scales of importance (Isaksen et al., 2009).

This section assesses updates in understanding of processes, modelling and observations since AR4 (see Section 2.3) on key reactive species contributing to RF. Note that aerosols, including processes responsible for the formation of aerosols, are extensively described in Section 7.3.

8.2.2 Global Chemistry Modelling in Coupled Model Intercomparison Project Phase 5

Because the distribution of NTCFs cannot be estimated from observations alone, coupled chemistry-climate simulations are required to define their evolution and associated RF. While several CMIP5 modeling groups performed simulations with interactive chemistry (i.e., computed simultaneously within the climate model), many models used as input pre-computed distributions of radiatively active gases and/or aerosols. To assess the distributions of chemical species and their respective RF, many research groups participated in the Atmospheric Chemistry and Climate Model Intercomparison Project (ACCMIP).

The ACCMIP simulations (Lamarque et al., 2013) were defined to provide information on the long-term changes in atmospheric composition with a few, well-defined atmospheric simulations. Because of the nature of the simulations (pre-industrial, present-day and future climates), only a limited number of chemistry-transport models (models which require a full definition of the meteorological fields needed to simulate physical processes and transport) participated in the ACCMIP project, which instead drew primarily from the same General Circulation Models (GCMs) as CMIP5 (see Lamarque et al., 2013 for a list of the participating models and their configurations), with extensive model evaluation against observations (Bowman et al., 2013; Lee et al., 2013; Shindell et al., 2013c; Voulgarakis et al., 2013; Young et al., 2013).

In all CMIP5/ACCMIP chemistry simulations, anthropogenic and biomass burning emissions are specified. More specifically, a single set of historical anthropogenic and biomass burning emissions (Lamarque et al., 2010) and one set of emissions for each of the RCPs (van Vuuren et al., 2011) was defined (Figure 8.2). This was designed to increase the comparability of simulations. However, these uniform emission specifications mask the existing uncertainty (e.g., Bond et al., 2007; Lu et al., 2011), so that there is in fact a considerable range in the estimates and time evolution of recent anthropogenic emissions (Granier et al., 2011). Historical reconstructions of biomass burning (wildfires and deforestation) also exhibit quite large uncertainties (Kasischke and Penner, 2004; Ito and Penner, 2005; Schultz et al., 2008; van der Werf et al., 2010). In addition, the RCP biomass burning projections do not include the feedback between climate change and fires discussed in Bowman et al. (2009), Pechony and Shindell (2010) and Thonicke et al. (2010). Finally, the RCP anthropogenic precursor emissions of NTCFs tend to span a smaller range than available from existing scenarios (van Vuuren et al., 2011). The ACCMIP simulations therefore provide an estimate of the uncertainty due to range of representation of physical and chemical processes in models, but do not incorporate uncertainty in emissions.

8.2.3 Chemical Processes and Trace Gas Budgets

8.2.3.1 Tropospheric Ozone

The RF from tropospheric ozone is strongly height- and latitude-dependent through coupling of ozone change with temperature, water vapour and clouds (Lacis et al., 1990; Berntsen et al., 1997; Worden et al., 2008, 2011; Bowman et al., 2013). Consequently, it is necessary to accurately estimate the change in the ozone spatio-temporal structure using global models and observations. It is also well established that surface ozone detrimentally affects plant productivity (Ashmore, 2005; Fishman et al., 2010), albeit estimating this impact on climate, although possibly significant, is still limited to a few studies (Sitch et al., 2007; UNEP, 2011).

Tropospheric ozone is a by-product of the oxidation of carbon monoxide (CO), CH_4, and non-CH_4 hydrocarbons in the presence of nitrogen oxides (NO_x). As emissions of these precursors have increased (Figure 8.2), tropospheric ozone has increased since pre-industrial times (Volz and Kley, 1988; Marenco et al., 1994) and over the last decades (Parrish et al., 2009; Cooper et al., 2010; Logan et al., 2012), but with important regional variations (Section 2.2). Ozone production is usually limited by the supply of HO_x ($OH + HO_2$) and NO_X ($NO + NO_2$) (Levy, 1971; Logan et al., 1981). Ozone's major chemical loss pathways in the troposphere are through (1) photolysis (to $O(^1D)$, followed by reaction with water vapour) and (2) reaction with HO_2 (Seinfeld and Pandis, 2006). The former pathway leads to couplings between stratospheric ozone (photolysis rate being a function of the overhead ozone column) and climate change (through water vapour). Observed surface ozone abundances typically range from less than 10 ppb over the tropical Pacific Ocean to more than 100 ppb downwind of highly emitting regions. The lifetime of ozone in the troposphere varies strongly with season and location: it may be as little as a few days in the tropical boundary layer, or as much as 1 year in the upper troposphere. Two recent studies give similar global mean lifetime of ozone: 22.3 ± 2 days (Stevenson et al., 2006) and 23.4 ± 2.2 days (Young et al., 2013).

For present (about 2000) conditions, the various components of the budget of global mean tropospheric ozone are estimated from the ACCMIP simulations and other model simulations since AR4 (Table 8.1). In particular, most recent models define a globally and annually averaged tropospheric ozone burden of (337 ± 23 Tg, 1-σ). Differences in the definition of the tropopause lead to inter-model variations of approximately 10% (Wild, 2007). This multi-model mean estimate of global annual tropospheric ozone burden has not significantly changed since the Stevenson et al. (2006) estimates (344 ± 39 Tg, 1-σ), and is consistent with the most recent satellite-based Ozone Monitoring Instrument–Microwave Limb Sounder (OMI-MLS; Ziemke et al., 2011) and Tropospheric Emission Spectrometer (TES; Osterman et al., 2008) climatologies.

Estimates of the ozone chemical sources and sinks (uncertainty estimates are quoted here as 1-σ) are less robust, with a net chemical production (production *minus* loss) of 618 ± 275 Tg yr^{-1} (Table 8.1), larger than the Atmospheric Composition Change: a European Network (ACCENT) results (442 ± 309 Tg yr^{-1}; Stevenson et al., 2006). Estimates of ozone deposition (1094 ± 264 Tg yr^{-1}) are slightly increased

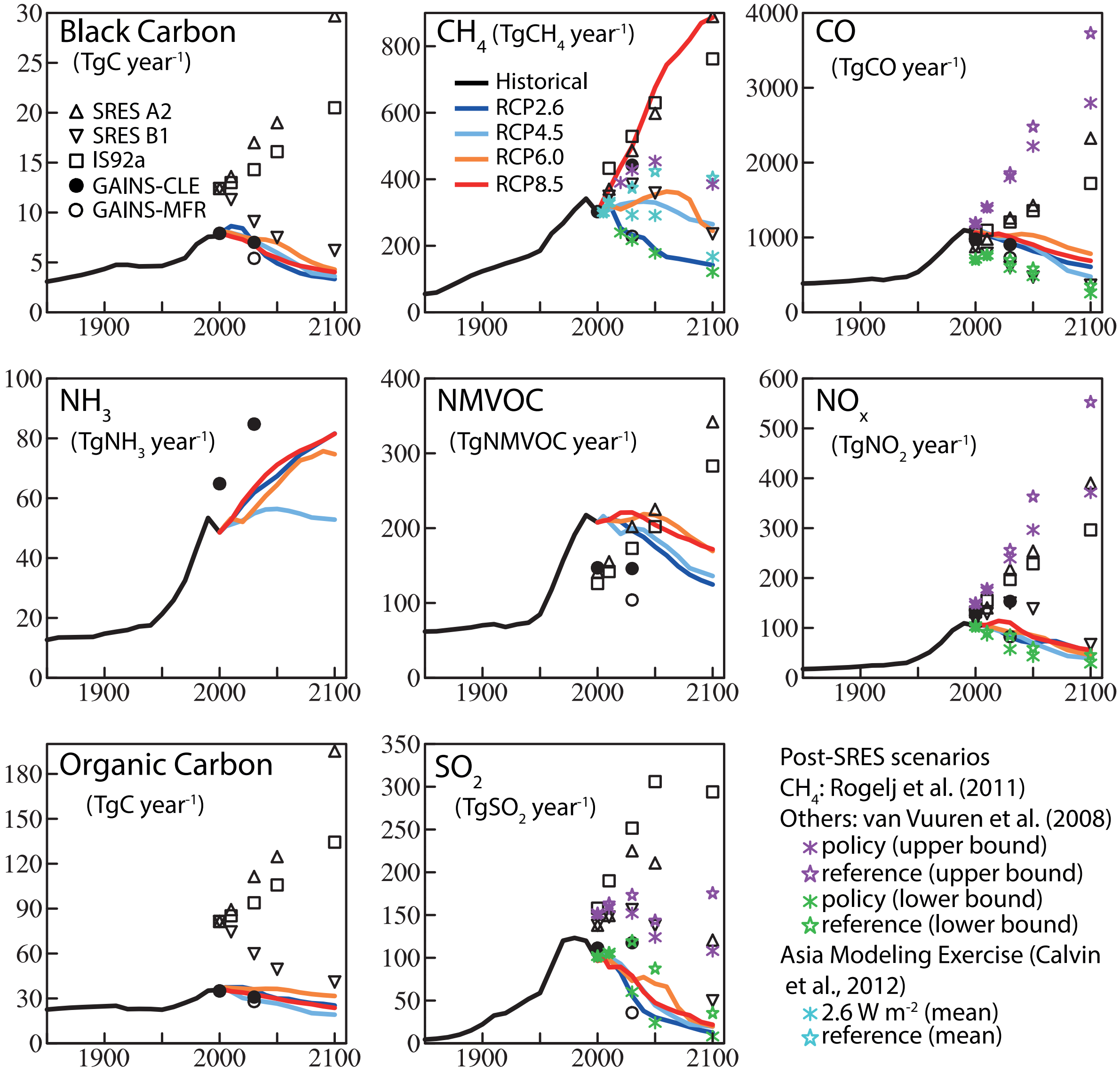


Figure 8.2 | Time evolution of global anthropogenic and biomass burning emissions 1850–2100 used in CMIP5/ACCMIP following each RCP. Historical (1850–2000) values are from Lamarque et al. (2010). RCP values are from van Vuuren et al. (2011). Emissions estimates from Special Report on Emission Scenarios (SRES) are discussed in Annex II; note that black carbon and organic carbon estimates were not part of the SRES and are shown here only for completeness. The Maximum Feasible Reduction (MFR) and Current Legislation (CLE) are discussed in Cofala et al. (2007); as biomass burning emissions are not included in that publication, a fixed amount, equivalent to the value in 2000 from the RCP estimates, is added (see Annex II for more details; Dentener et al., 2006). The post-SRES scenarios are discussed in Van Vuuren et al. (2008) and Rogelj et al. (2011). For those, only the range (minimum to maximum) is shown. Global emissions from the Asian Modelling Exercise are discussed in Calvin et al. (2012). Regional estimates are shown in Supplementary Material Figure 8.SM.1 and Figure 8.SM.2 for the historical and RCPs.

since ACCENT (1003 ± 200 Tg yr^{-1}) while estimates of the net influx of ozone from the stratosphere to the troposphere (477 ± 96 Tg yr^{-1}) have slightly decreased since ACCENT (552 ± 168 Tg yr^{-1}). Additional model estimates of this influx (Hegglin and Shepherd, 2009; Hsu and Prather, 2009) fall within both ranges, as do estimates based on observations (Murphy and Fahey, 1994; Gettelman et al., 1997; Olsen et al., 2002), all estimates being sensitive to their choice of tropopause definition and interannual variability.

Model simulations for present-day conditions or the recent past are evaluated (Figure 8.3) against frequent ozonesonde measurements (Logan, 1999; Tilmes et al., 2012) and additional surface, aircraft and satellite measurements. The ACCMIP model simulations (Figure 8.3) indicate 10 to 20% negative bias at 250 hPa in the SH tropical region, and a slight underestimate in NH tropical region. Comparison with satellite-based estimates of tropospheric ozone column (Ziemke et al., 2011) indicates an annual mean bias of –4.3 ± 29 Tg (with a spatial correlation of 0.87 ± 0.07, 1-σ) for the ACCMIP simulations (Young et al., 2013). Overall, our ability to simulate tropospheric ozone burden for present (about 2000) has not substantially changed since AR4. Evaluation (using a subset of two ACCMIP models) of simulated trends (1960s to present or shorter) in surface ozone against observations at remote surface sites (see Section 2.2) indicates an underestimation, especially in the NH (Lamarque et al., 2010). Although this limits the ability to represent recent ozone changes, it is unclear how this translates into an uncertainty on changes since pre-industrial times.

Table 8.1 | Summary of tropospheric ozone global budget model and observation estimates for present (about 2000) conditions. Focus is on modelling studies published since AR4. STE stands for stratosphere–troposphere exchange. All uncertainties quoted as 1 standard deviation (68% confidence interval).

Burden	Production	Loss	Deposition	STE	Reference
Tg	Tg yr^{-1}	Tg yr^{-1}	Tg yr^{-1}	Tg yr^{-1}	
Modelling Studies					
337 ± 23	4877 ± 853	4260 ± 645	1094 ± 264	477 ± 96	Young et al. (2013); ACCMIP
323	N/A	N/A	N/A	N/A	Archibald et al. (2011)
330	4876	4520	916	560	Kawase et al. (2011)
312	4289	3881	829	421	Huijnen et al. (2010)
334	3826	3373	1286	662	Zeng et al. (2010)
324	4870	4570	801	502	Wild and Palmer (2008)
314	N/A	N/A	1035	452	Zeng et al. (2008)
319	4487	3999	N/A	500	Wu et al. (2007)
372	5042	4507	884	345	Horowitz (2006)
349	4384	3972	808	401	Liao et al. (2006)
344 ± 39	5110 ± 606	4668 ± 727	1003 ± 200	552 ± 168	Stevenson et al. (2006); ACCENT
314 ± 33	4465 ± 514	4114 ± 409	949 ± 222	529 ± 105	Wild (2007) (post-2000 studies)
N/A	N/A	N/A	N/A	515	Hsu and Prather (2009)
N/A	N/A	N/A	N/A	655	Hegglin and Shepherd (2009)
N/A	N/A	N/A	N/A	383–451	Clark et al. (2007)
Observational Studies					
333	N/A	N/A	N/A	N/A	Fortuin and Kelder (1998)
327	N/A	N/A	N/A	N/A	Logan (1999)
325	N/A	N/A	N/A	N/A	Ziemke et al. (2011); 60S–60N
319–351	N/A	N/A	N/A	N/A	Osterman et al. (2008); 60S–60N
N/A	N/A	N/A	N/A	449 (192–872)	Murphy and Fahey (1994)
N/A	N/A	N/A	N/A	510 (450–590)	Gettelman et al. (1997)
N/A	N/A	N/A	N/A	500 ± 140	Olsen et al. (2001)

In most studies ‘pre-industrial’ does not identify a specific year but is usually assumed to correspond to 1850s levels; no observational information on ozone is available for that time period. Using the Lamarque et al. (2010) emissions, the ACCMIP models (Young et al., 2013) are unable to reproduce the low levels of ozone observed at Montsouris 1876–1886 (Volz and Kley, 1988). The other early ozone measurements using the Schönbein paper are controversial (Marenco et al., 1994) and assessed to be of qualitative use only. The main uncertainty in estimating the pre-industrial to present-day change in ozone therefore remains the lack of constraint on emission trends because of the very incomplete knowledge of pre-industrial ozone concentrations, of which no new information is available. The uncertainty on pre-industrial conditions is not confined to ozone but applies to aerosols as well (e.g., Schmidt et al., 2012), although ice and lake core records provide some constraint on pre-industrial aerosol concentrations.

The ACCMIP results provide an estimated tropospheric ozone increase (Figure 8.4) from 1850 to 2000 of 98 ± 17 Tg (model range), similar to AR4 estimates. Skeie et al. (2011a) found an additional 5% increase in the anthropogenic contribution to the ozone burden between 2000 and 2010, which translates into an approximately 1.5% increase in tropospheric ozone burden. A best estimate of the change in ozone since 1850 is assessed at 100 ± 25 Tg (1-σ). Attribution simulations (Stevenson et al., 2013) indicate unequivocally that anthropogenic changes in ozone precursor emissions are responsible for the increase between 1850 and present or into the future.

8.2.3.2 Stratospheric Ozone and Water Vapour

Stratospheric ozone has experienced significant depletion since the 1960s due to bromine and chlorine-containing compounds (Solomon, 1999), leading to an estimated global decrease of stratospheric ozone of 5% between the 1970s and the mid-1990s, the decrease being largest over Antarctica (Fioletov et al., 2002). Most of the ozone loss is associated with the long-lived bromine and chlorine-containing compounds (chlorofluorocarbons and substitutes) released by human activities, in addition to N_2O. This is in addition to a background level of natural emissions of short-lived halogens from oceanic and volcanic sources.

With the advent of the Montreal Protocol and its amendments, emissions of chlorofluorocarbons (CFCs) and replacements have strongly declined (Montzka et al., 2011), and signs of ozone stabilization and even possibly recovery have already occurred (Mader et al., 2010; Salby et al., 2012). A further consequence is that N_2O emissions (Section 8.2.3.4) *likely* dominate all other emissions in terms of ozone-depleting

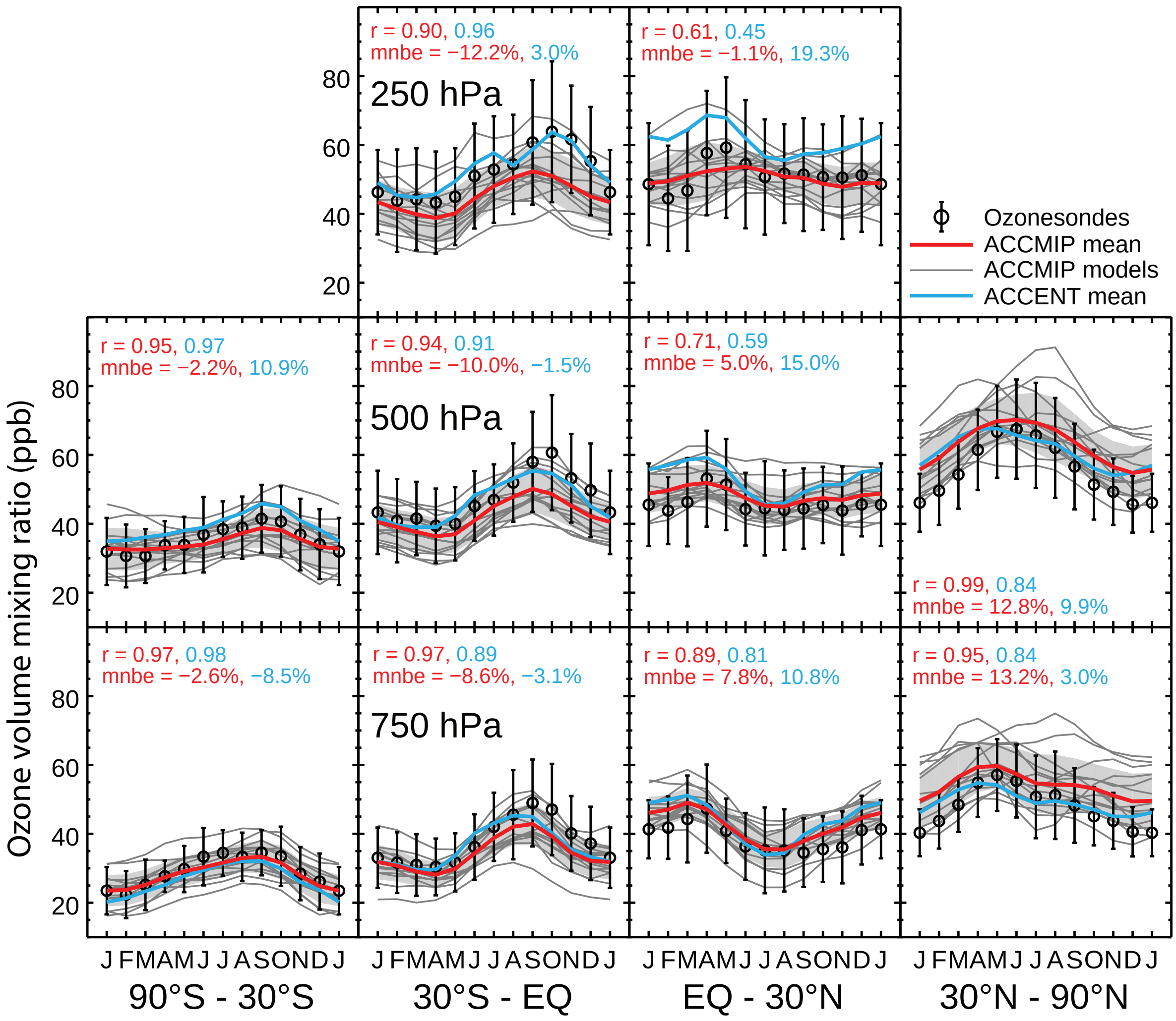


Figure 8.3 | Comparisons between observations and simulations for the monthly mean ozone for ACCMIP results (Young et al., 2013). ACCENT refers to the model results in Stevenson et al. (2006). For each box, the correlation of the seasonal cycle is indicated by the *r* value, while the mean normalized bias estimated is indicated by *mnbe* value.

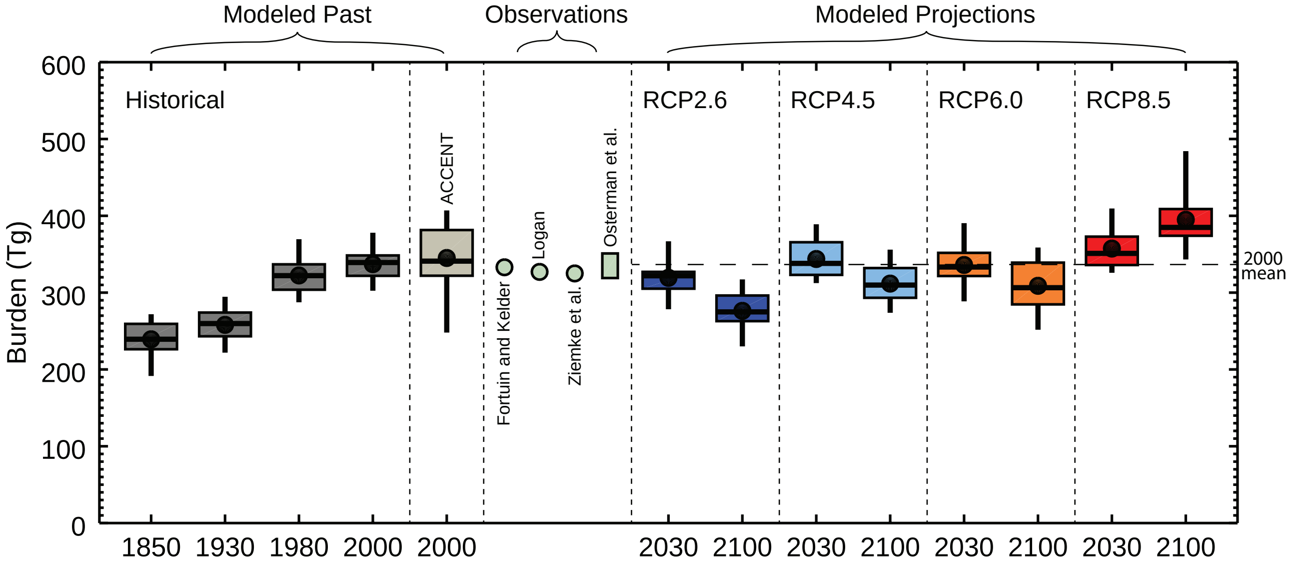


Figure 8.4 | Time evolution of global tropospheric ozone burden (in Tg(O_3)) from 1850 to 2100 from ACCMIP results, ACCENT results (2000 only), and observational estimates (see Table 8.1). The box, whiskers, line and dot show the interquartile range, full range, median and mean burdens and differences, respectively. The dashed line indicates the 2000 ACCMIP mean. (Adapted from Young et al., 2013.)

potential (Ravishankara et al., 2009). Chemistry-climate models with resolved stratospheric chemistry and dynamics recently predicted an estimated global mean total ozone column recovery to 1980 levels to occur in 2032 (multi-model mean value, with a range of 2024 to 2042) under the A1B scenario (Eyring et al., 2010a). Increases in the stratospheric burden and acceleration of the stratospheric circulation leads to an increase in the stratosphere–troposphere flux of ozone (Shindell et al., 2006c; Grewe, 2007; Hegglin and Shepherd, 2009; Zeng et al., 2010). This is also seen in recent RCP8.5 simulations, with the impact of increasing tropospheric burden (Kawase et al., 2011; Lamarque et al., 2011). However, observationally based estimates of recent trends in age of air (Engel et al., 2009; Stiller et al., 2012) do not appear to be consistent with the acceleration of the stratospheric circulation found in model simulations, possibly owing to inherent difficulties with extracting trends from SF_6 observations (Garcia et al., 2011).

Oxidation of CH_4 in the stratosphere (see Section 8.2.3.3) is a significant source of water vapour and hence the long-term increase in CH_4 leads to an anthropogenic forcing (see Section 8.3) in the stratosphere. Stratospheric water vapour abundance increased by an average of 1.0 ± 0.2 (1-σ) ppm during 1980–2010, with CH_4 oxidation explaining approximately 25% of this increase (Hurst et al., 2011). Other factors contributing to the long-term change in water vapour include changes in tropical tropopause temperatures (see Section 2.2.2.1).

8.2.3.3 Methane

The surface mixing ratio of CH_4 has increased by 150% since pre-industrial times (Sections 2.2.1.1.2 and 8.3.2.2), with some projections indicating a further doubling by 2100 (Figure 8.5). Bottom-up estimates of present CH_4 emissions range from 542 to 852 TgCH$_4$ yr^{-1} (see Table 6.8), while a recent top-down estimate with uncertainty analysis is 554 ± 56 TgCH$_4$ yr^{-1} (Prather et al., 2012). All quoted uncertainties in Section 8.2.3.3 are defined as 1-σ.

The main sink of CH_4 is through its reaction with the hydroxyl radical (OH) in the troposphere (Ehhalt and Heidt, 1973). A primary source of tropospheric OH is initiated by the photodissociation of ozone, followed by reaction with water vapour (creating sensitivity to humidity, cloud cover and solar radiation) (Levy, 1971; Crutzen, 1973). The other main source of OH is through secondary reactions (Lelieveld et al., 2008), although some of those reactions are still poorly understood (Paulot et al., 2009; Peeters et al., 2009; Taraborrelli et al., 2012). A recent estimate of the CH_4 tropospheric chemical lifetime with respect to OH constrained by methyl chloroform surface observations is 11.2 ± 1.3 years (Prather et al., 2012). In addition, bacterial uptake in soils provides an additional small, less constrained loss (Fung et al., 1991); estimated lifetime = 120 ± 24 years (Prather et al., 2012), with another small loss in the stratosphere (Ehhalt and Heidt, 1973); estimated lifetime = 150 ± 50 years (Prather et al., 2012). Halogen chemistry in the troposphere also contributes to some tropospheric CH_4 loss (Allan et al., 2007), estimated lifetime = 200 ± 100 years (Prather et al., 2012).

The ACCMIP estimate for present CH_4 lifetime with respect to tropospheric OH varies quite widely (9.8 ± 1.6 years (Voulgarakis et al., 2013)), slightly shorter than the 10.2 ± 1.7 years in (Fiore et al. (2009), but much shorter than the methyl chloroform-based estimate of 11.2 ± 1.3 years (Prather et al., 2012). A partial explanation for the range in CH_4 lifetime changes can be found in the degree of representation of chemistry in chemistry–climate models. Indeed, Archibald et al. (2010) showed that the response of OH to increasing nitrogen oxides strongly depends on the treatment of hydrocarbon chemistry in a model. The impact on CH_4 distribution in the ACCMIP simulations is, however, rather limited because most models prescribed CH_4 as a time-varying lower-boundary mixing ratio (Lamarque et al., 2013).

The chemical coupling between OH and CH_4 leads to a significant amplification of an emission impact; that is, increasing CH_4 emissions decreases tropospheric OH which in turn increases the CH_4 lifetime and therefore its burden. The OH-lifetime sensitivity for CH_4, s_OH = –δln(OH)/δln(CH4), was estimated in Chapter 4 of TAR to be 0.32, implying a 0.32% decrease in tropospheric mean OH (as weighted by CH_4 loss) for a 1% increase in CH_4. The Fiore et al. (2009) multi-model (12 models) study provides a slightly smaller value (0.28 ± 0.03). Holmes et al. (2013) gives a range 0.31 ± 0.04 by combining Fiore et al. (2009), Holmes et al. (2011) and three new model results (0.36, 0.31, 0.27). Only two ACCMIP models reported values (0.19 and 0.26; Voulgarakis et al., 2013). The projections of future CH_4 in Chapter 11 use the Holmes et al. (2013) range and uncertainty, which at the 2-σ level covers all but one model result. The feedback factor *f*, the ratio of the

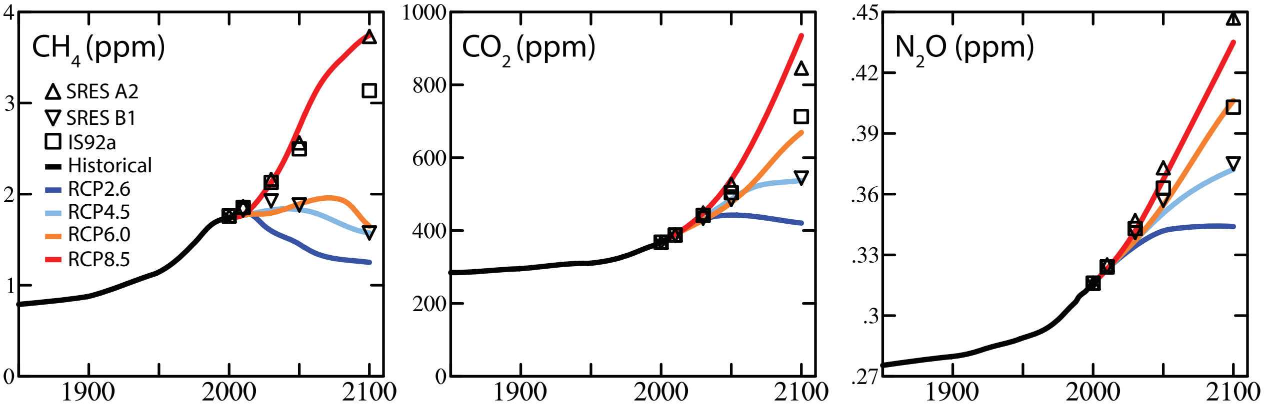


Figure 8.5 | Time evolution of global-averaged mixing ratio of long-lived species1850–2100 following each RCP; blue (RCP2.6), light blue (RCP4.5), orange (RCP6.0) and red (RCP8.5). (Based on Meinshausen et al., 2011b.)

lifetime of a CH_4 perturbation to the lifetime of the total CH_4 burden, is calculated as f = 1/(1-s). Other CH_4 losses, which are relatively insensitive to CH_4 burden, must be included so that $f = 1.34 \pm 0.06$, (slightly larger but within the range of the Stevenson et al. (2006) estimate of 1.29 ± 0.04, based on six models), leading to an overall perturbation lifetime of 12.4 ± 1.4 years, which is used in calculations of metrics in Section 8.7. Additional details are provided in the Supplementary Material Section 8.SM.2.

8.2.3.4 Nitrous Oxide

Nitrous oxide (N_2O) in 2011 has a surface concentration 19% above its 1750 level (Sections 2.2.1.1.3 and 8.3.2.3). Increases in N_2O lead to depletion of mid- to upper-stratospheric ozone and increase in mid-latitude lower stratospheric ozone (as a result of increased photolysis rate from decreased ozone above). This impacts tropospheric chemistry through increase in stratosphere–troposphere exchange of ozone and odd nitrogen species and increase in tropospheric photolysis rates and OH formation (Prather and Hsu, 2010). Anthropogenic emissions represent around 30 to 45% of the present-day global total, and are mostly from agricultural and soil sources (Fowler et al., 2009) and fossil-fuel activities. Natural emissions come mostly from microbial activity in the soil. The main sink for N_2O is through photolysis and oxidation reactions in the stratosphere, leading to an estimated lifetime of 131 ± 10 years (Prather et al., 2012), slightly larger than previous estimates (Prather and Hsu, 2010; Montzka et al., 2011). The addition of N_2O to the atmosphere changes its own lifetime through feedbacks that couple N_2O to stratospheric NO_y and ozone depletion (Prather, 1998; Ravishankara et al., 2009; Prather and Hsu, 2010), so that the lifetime of a perturbation is less than that of the total burden, 121 ± 10 years (1-σ; Prather et al., 2012) and is used in calculations of metrics (Section 8.7).

8.2.3.5 Halogenated Species

Halogenated species can be powerful greenhouse gases (GHGs). Those containing chlorine and bromine also deplete stratospheric ozone and are referred to as ozone-depleting substances (ODSs). Most of those compounds do not have natural emissions and, because of the implementation of the Montreal Protocol and its amendments, total emissions of ODSs have sharply decreased since the 1990s (Montzka et al., 2011). For CFCs, perfluorocarbons (PFCs) and SF_6 the main loss is through photolysis in the stratosphere. The CFC substitutes (hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs)) are destroyed by OH oxidation in the troposphere. Their global concentration has steadily risen over the recent past (see Section 2.2.1.1.4).

8.2.3.6 Aerosols

Aerosol particles are present in the atmosphere with size ranges from a few nanometres to tens of micrometres. They are the results of direct emission (primary aerosols: BC, OC, sea salt, dust) into the atmosphere or as products of chemical reactions (secondary inorganic aerosols: sulphate, nitrate, ammonium; and secondary organic aerosols (SOAs)) occurring in the atmosphere. Secondary inorganic aerosols are the products of reactions involving sulphur dioxide, ammonia and nitric oxide emissions. SOAs are the result of chemical reactions of non-methane hydrocarbons (and their products) with the hydroxyl radical (OH), ozone, nitrate (NO_3) or photolysis (Hallquist et al., 2009). Thus although many hydrocarbons in the atmosphere are of biogenic origin, anthropogenic pollutants can have impacts on their conversion to SOAs. There is tremendous complexity and still much uncertainty in the processes involved in the formation of SOAs (Hallquist et al., 2009; Carslaw et al., 2010). Additional information can be found in Section 7.3.2.

Once generated, the size and composition of aerosol particles can be modified by additional chemical reactions, condensation or evaporation of gaseous species and coagulation (Seinfeld and Pandis, 2006). It is this set of processes that defines their physical, chemical and optical properties, and hence their impact on radiation and clouds, with large regional and global differences (see Section 7.3.3). Furthermore, their distribution is affected by transport and deposition, defining a residence time in the troposphere of usually a few days (Textor et al., 2006).

8.3 Present-Day Anthropogenic Radiative Forcing

Human activity has caused a variety of changes in different forcing agents in the atmosphere or land surface. A large number of GHGs have had a substantial increase over the Industrial Era and some of these gases are entirely of anthropogenic origin. Atmospheric aerosols have diverse and complex influences on the climate. Human activity has modified the land cover and changed the surface albedo. Some of the gases and aerosols are directly emitted to the atmosphere whereas others are secondary products from chemical reactions of emitted species. The lifetimes of these different forcing agents vary substantially. This section discusses all known anthropogenic forcing agents of non-negligible importance and their quantification in terms of RF or ERF based on changes in abundance over the 1750–2011 period.

In this section we determine the RFs for WMGHGs and heterogeneously distributed species in fundamentally different ways. As described in Box 8.2, the concentrations of WMGHGs can be determined from observations at a few surface sites. For the pre-industrial concentrations these are typically from trapped air in polar ice or firn (see Section 2.2.1). Thus the RFs from WMGHGs are determined entirely from observations (Section 8.3.2). In contrast, we do not have sufficient pre-industrial or present-day observations of heterogeneously distributed forcing agents (e.g., ozone and aerosols) to be able to characterize their RF; therefore we instead have to rely on chemistry–climate models (Sections 8.3.3 and 8.3.4).

8.3.1 Updated Understanding of the Spectral Properties of Greenhouse Gases and Radiative Transfer Codes

RF estimates are performed with a combination of radiative transfer codes typical for GCMs as well as more detailed radiative transfer codes. Physical properties are needed in the radiative transfer codes such as spectral properties for gases. The HITRAN (HIgh Resolution TRANsmission molecular absorption) database (Rothman, 2010) is widely used in radiative transfer models. Some researchers studied the difference among different editions of HITRAN databases for diverse uses (Feng et al., 2007; Kratz, 2008; Feng and Zhao, 2009; Fomin and Falaleeva, 2009; Lu et al., 2012). Model calculations have shown that modifications of the spectroscopic characteristics tend to have a modest effect on the determination of RF estimates of order 2 to 3% of the calculated RF attributed to the combined doubling of CO_2, N_2O and CH_4. These results showed that even the largest overall RF induced by differences among the HITRAN databases is considerably smaller than the range reported for the modelled RF estimates; thus the line parameter updates to the HITRAN database are not a significant source for discrepancies in the RF calculations appearing in the IPCC reports. However, the more recent HITRAN data set is still recommended, as the HITRAN process offers internal verification and tends to progress closer to the best laboratory measurements. It is found that the differences among the water vapour continuum absorption formulations tend to be comparable to the differences among the various HITRAN databases (Paynter and Ramaswamy, 2011); but use of the older Robert continuum formula produces significantly larger flux differences, thus, replacement of the older continuum is warranted (Kratz, 2008) and there are still numerous unresolved issues left in the continuum expression, especially related to shortwave radiative transfer (Shine et al., 2012). Differences in absorption data from various HITRAN versions are *very likely* a small contributor to the uncertainty in RF of GHGs.

Line-by-line (LBL) models using the HITRAN data set as an input are the benchmark of radiative transfer models for GHGs. Some researchers compared different LBL models (Zhang et al., 2005; Collins et al., 2006) and line-wing cutoff, line-shape function and gas continuum absorption treatment effects on LBL calculations (Zhang et al., 2008; Fomin and Falaleeva, 2009). The agreement between LBL codes has been investigated in many studies and found to generally be within a few percent (e.g., Collins et al., 2006; Iacono et al., 2008; Forster et al., 2011a) and to compare well to observed radiative fluxes under controlled situations (Oreopoulos et al., 2012). Forster et al. (2011a) evaluated global mean radiatively important properties of chemistry climate models (CCMs) and found that the combined WMGHG global annual mean instantaneous RF at the tropopause is within 30% of LBL models for all CCM radiation codes tested. The accuracies of the LW RF due to CO_2 and tropospheric ozone increase are generally very good and within 10% for most of the participation models, but problems remained in simulating RF for stratospheric water vapour and ozone changes with errors between 3% and 200% compared to LBL models. Whereas the differences in the results from CCM radiation codes were large, the agreement among the LW LBL codes was within 5%, except for stratospheric water vapour changes.

Most intercomparison studies of the RF of GHGs are for clear-sky and aerosol-free conditions; the introduction of clouds would greatly complicate the targets of research and are usually omitted in the intercomparison exercises of GCM radiation codes and LBL codes (e.g., Collins et al., 2006; Iacono et al., 2008). It is shown that clouds can reduce the magnitude of RF due to GHGs by about 25% (Forster et al., 2005; Worden et al., 2011; Zhang et al., 2011), but the influence of clouds on the diversity in RF is found to be within 5% in four detailed radiative transfer schemes with realistic cloud distributions (Forster et al., 2005). Estimates of GHG RF are based on the LBL codes or the radiative transfer codes compared and validated against LBL models, and the uncertainty range from AR4 in the RF of GHG of 10% is retained. We underscore that uncertainty in RF calculations in many GCMs is substantially higher owing both to radiative transfer codes and meteorological data such as clouds adopted in the simulations.

8.3.2 Well-mixed Greenhouse Gases

AR4 assessed the RF from 1750 to 2005 of the WMGHGs to be 2.63 W m^{-2}. The four most important gases were CO_2, CH_4, dichlorodifluoromethane (CFC-12) and N_2O in that order. Halocarbons, comprising CFCs, HCFCs, HFCs, PFCs and SF_6, contributed 0.337 W m^{-2} to the total. Uncertainties (90% confidence ranges) were assessed to be approximately 10% for the WMGHGs. The major changes to the science since AR4 are the updating of the atmospheric concentrations, the inclusion of new species (NF_3 and SO_2F_2) and discussion of ERF for CO_2. Since AR4 N_2O has overtaken CFC-12 as the third largest contributor to RF. The total WMGHG RF is now 2.83 (2.54 to 3.12) W m^{-2}.

The RFs in this section are derived from the observed differences in concentrations of the WMGHGs between 1750 and 2011. The concentrations of CO_2, CH_4 and N_2O vary throughout the pre-industrial era, mostly due to varying climate, with a possible small contribution from anthropogenic emissions (MacFarling Meure et al., 2006). These variations do not contribute to uncertainty in the RF as strictly defined here, but do affect the RF attribution to anthropogenic emissions. On centennial time scales, variations in late Holocene concentrations of CO_2 are around 10 ppm (see note to Table 2.1), much larger than the uncertainty in the 1750 concentration. This would equate to a variation in the RF of 10%. For CH_4 and N_2O the centennial variations are comparable to the uncertainties in the 1750 concentrations and so do not significantly affect the estimate of the 1750 value used in calculating RF.

8.3.2.1 Carbon Dioxide

The tropospheric mixing ratio of CO_2 has increased globally from 278 (276–280) ppm in 1750 to 390.5 (390.3 to 390.7) ppm in 2011 (see Section 2.2.1.1.1). Here we assess the RF due to changes in atmospheric concentration rather than attributing it to anthropogenic emissions. Section 6.3.2.6 describes how only a fraction of the historical CO_2 emissions have remained in the atmosphere. The impact of land use change on CO_2 from 1850 to 2000 was assessed in AR4 to be 12 to 35 ppm (0.17 to 0.51 W m^{-2}).

Using the formula from Table 3 of Myhre et al. (1998), and see Supplementary Material Table 8.SM.1, the CO_2 RF (as defined in Section 8.1) from 1750 to 2011 is 1.82 (1.63 to 2.01) W m^{-2}. The uncertainty is dominated by the radiative transfer modelling which is assessed to be 10% (Section 8.3.1). The uncertainty in the knowledge of 1750 concentrations contributes only 2% (see Supplementary Material Table 8.SM.2)

Table 8.2 shows the concentrations and RF in AR4 (2005) and 2011 for the most important WMGHGs. Figure 8.6 shows the time evolution of RF and its rate of change. Since AR4, the RF of CO_2 has increased by 0.16 W m^{-2} and continues the rate noted in AR4 of almost 0.3 W m^{-2} per decade. As shown in Figure 8.6(d) the rate of increase in the RF from the WMGHGs over the last 15 years has been dominated by CO_2. Since AR4, CO_2 has accounted for more than 80% of the WMGHG RF increase. The interannual variability in the rate of increase in the CO_2 RF is due largely to variation in the natural land uptake whereas the trend is driven by increasing anthropogenic emissions (see Figure 6.8 in Section 6.3.1).

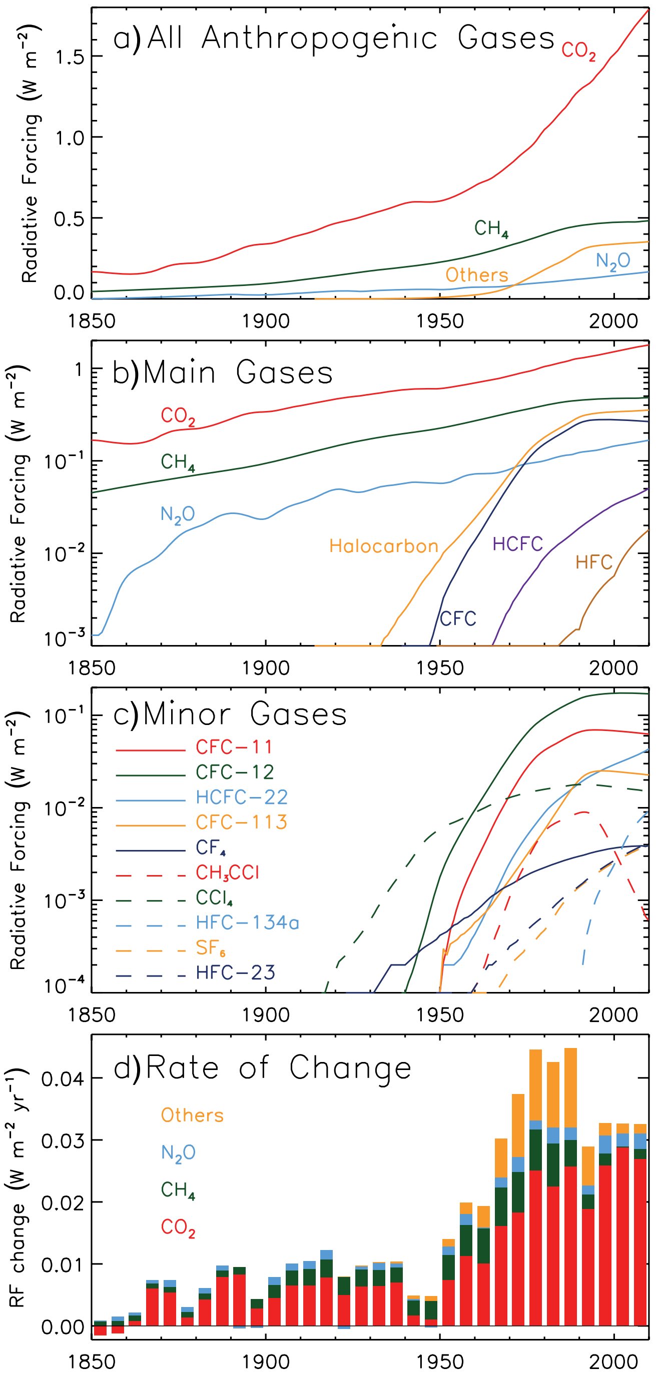


Figure 8.6 | (a) Radiative forcing (RF) from the major well-mixed greenhouse gases (WMGHGs) and groups of halocarbons from 1850 to 2011 (data from Tables A.II.1.1 and A.II.4.16), (b) as (a) but with a logarithmic scale, (c) RF from the minor WMGHGs from 1850 to 2011 (logarithmic scale). (d) Rate of change in forcing from the major WMGHGs and groups of halocarbons from 1850 to 2011.

As described in Section 8.1.1.3, CO_2 can also affect climate through physical effects on lapse rates and clouds, leading to an ERF that will be different from the RF. Analysis of CMIP5 models (Vial et al., 2013) found a large negative contribution to the ERF (20%) from the increase in land surface temperatures which was compensated for by positive contributions from the combined effects on water vapour, lapse rate, albedo and clouds. It is therefore not possible to conclude with the current information whether the ERF for CO_2 is higher or lower than the RF. Therefore we assess the ratio ERF/RF to be 1.0 and assess our uncertainty in the CO_2 ERF to be (–20% to 20%). We have *medium confidence* in this based on our understanding that the physical processes responsible for the differences between ERF and RF are small enough to be covered within the 20% uncertainty.

There are additional effects mediated through plant physiology, reducing the conductance of the plant stomata and hence the transpiration of water. Andrews et al. (2012b) find a physiological enhancement of the adjusted forcing by 3.5% due mainly to reductions in low cloud. This is smaller than a study with an earlier model by Doutriaux-Boucher et al. (2009) which found a 10% effect. Longer-term impacts of CO_2 on vegetation distributions also affect climate (O'ishi et al., 2009; Andrews et al., 2012b) but because of the longer time scale we choose to class these as feedbacks rather than rapid adjustments.

8.3.2.2 Methane

Globally averaged surface CH_4 concentrations have risen from 722 ± 25 ppb in 1750 to 1803 ± 2 ppb by 2011 (see Section 2.2.1.1.2). Over that time scale the rise has been due predominantly to changes in anthropogenic-related CH_4. Anthropogenic emissions of other compounds have also affected CH_4 concentrations by changing its removal rate (Section 8.2.3.3). Using the formula from Myhre et al. (1998) (see Supplementary Material Table 8.SM.1) the RF for CH_4 from 1750 to 2011 is 0.48 ± 0.05 W m^{-2}, with an uncertainty dominated by the radiative transfer calculation. This increase of 0.01 W m^{-2} since AR4 is due to the 29 ppb increase in the CH_4 mixing ratio. This is much larger than the 11 ppb increase between TAR and AR4, and has been driven by increases in net natural and anthropogenic emissions, but the relative contributions are not well quantified. Recent trends in CH_4 and their causes are discussed in Sections 2.2.1.1.2 and 6.3.3.1. CH_4 concentrations do vary with latitude and decrease above the tropopause; however, this variation contributes only 2% to the uncertainty in RF (Freckleton et al., 1998).

In this section only the direct forcing from changing CH_4 concentrations is addressed. CH_4 emissions can also have indirect effects on climate through impacts on CO_2, stratospheric water vapour, ozone, sulphate aerosol and lifetimes of HFCs and HCFCs (Boucher et al., 2009; Shindell et al., 2009; Collins et al., 2010). Some of these are discussed further in Sections 8.3.3, 8.5.1 and 8.7.2.

8.3.2.3 Nitrous Oxide

Concentrations of nitrous oxide have risen from 270 ± 7 ppb in 1750 to 324.2 ± 0.1 ppb in 2011, an increase of 5 ppb since 2005 (see Section 2.2.1.1.3). N_2O now has the third largest forcing of the anthropogenic gases, at 0.17 ± 0.03 W m^{-2} an increase of 6% since 2005 (see Table

8.2) where the uncertainty is due approximately equally to the pre-industrial concentration and radiative transfer. Only the direct RF from changing nitrous oxide concentrations is included. Indirect effects of N_2O emissions on stratospheric ozone are not taken into account here but are discussed briefly in Section 8.7.2.

8.3.2.4 Other Well-mixed Greenhouse Gases

RFs of the other WMGHG are shown in Figure 8.6 (b and c) and Table 8.2. The contribution of groups of halocarbons to the rate of change of WMGHG RF is shown in Figure 8.6 (d). Between 1970 and 1990 halocarbons made a significant contribution to the rate of change of RF. The rate of change in the total WMGHG RF was higher in 1970 to 1990 with *high confidence* compared to the present owing to higher contribution from non-CO_2 gases especially the halocarbons. Since the Montreal Protocol and its amendments, the rate of change of RF from halocarbons and related compounds has been much less, but still just positive (total RF of 0.360 W m^{-2} in 2011 compared to 0.351 W m^{-2} in 2005) as the growth of HCFCs, HFCs, PFCs and other halogens (SF_6, SO_2F_2, NF_3) RFs (total 0.022 W m^{-2} since 2005) more than compensates

Table 8.2 | Present-day mole fractions (in ppt(pmol mol^{-1}) except where specified) and RF (in W m^{-2}) for the WMGHGs. Concentration data are averages of National Oceanic and Atmospheric Administration (NOAA) and Advanced Global Atmospheric Gases Experiment (AGAGE) observations where available. CO_2 concentrations are the average of NOAA and SIO. See Table 2.1 for more details of the data sources. The data for 2005 (the time of the AR4 estimates) are also shown. Some of the concentrations vary slightly from those reported in AR4 owing to averaging different data sources. Radiative efficiencies for the minor gases are given in Table 8.A.1. Uncertainties in the RF for all gases are dominated by the uncertainties in the radiative efficiencies. We assume the uncertainties in the radiative efficiencies to be perfectly correlated between the gases, and the uncertainties in the present day and 1750 concentrations to be uncorrelated.

	Concentrations (ppt)		Radiative forcing[a] (W m^{-2})	
Species	**2011**	**2005**	**2011**	**2005**
CO_2 (ppm)	391 ± 0.2	379	1.82 ± 0.19	1.66
CH_4 (ppb)	1803 ± 2	1774	0.48 ± 0.05	0.47[e]
N_2O (ppb)	324 ± 0.1	319	0.17 ± 0.03	0.16
CFC-11	238 ± 0.8	251	0.062	0.065
CFC-12	528 ± 1	542	0.17	0.17
CFC-13	2.7		0.0007	
CFC-113	74.3 ± 0.1	78.6	0.022	0.024
CFC-115	8.37	8.36	0.0017	0.0017
HCFC-22	213 ± 0.1	169	0.0447	0.0355
HCFC-141b	21.4 ± 0.1	17.7	0.0034	0.0028
HCFC-142b	21.2 ± 0.2	15.5	0.0040	0.0029
HFC-23	24.0 ± 0.3	18.8	0.0043	0.0034
HFC-32	4.92	1.15	0.0005	0.0001
HFC-125	9.58 ± 0.04	3.69	0.0022	0.0008
HFC-134a	62.7 ± 0.3	34.3	0.0100	0.0055
HFC-143a	12.0 ± 0.1	5.6	0.0019	0.0009
HFC-152a	6.4 ± 0.1	3.4	0.0006	0.0003
SF_6	7.28 ± 0.03	5.64	0.0041	0.0032
SO_2F_2	1.71	1.35	0.0003	0.0003
NF_3	0.9	0.4	0.0002	0.0001
CF_4	79.0 ± 0.1	75.0	0.0040	0.0036
C_2F_6	4.16 ± 0.02	3.66	0.0010	0.0009
CH_3CCl_3	6.32 ± 0.07	18.32	0.0004	0.0013
CCl_4	85.8 ± 0.8	93.1	0.0146	0.0158
CFCs			0.263 ± 0.026[b]	0.273[c]
HCFCs			0.052 ± 0.005	0.041
Montreal gases[d]			0.330 ± 0.033	0.331
Total halogens			0.360 ± 0.036	0.351[f]
Total			2.83 ± 0.029	2.64

Notes:

[a] Pre-industrial values are zero except for CO_2 (278 ppm), CH_4 (722 ppb), N_2O (270 ppb) and CF_4 (35 ppt).

[b] Total includes 0.007 W m^{-2} to account for CFC-114, Halon-1211 and Halon-1301.

[c] Total includes 0.009 W m^{-2} forcing (as in AR4) to account for CFC-13, CFC-114, CFC-115, Halon-1211 and Halon-1301.

[d] Defined here as CFCs + HCFCs + CH_3CCl_3 + CCl_4.

[e] The value for the 1750 methane concentrations has been updated from AR4 in this report, thus the 2005 methane RF is slightly lower than reported in AR4.

[f] Estimates for halocarbons given in the table may have changed from estimates reported in AR4 owing to updates in radiative efficiencies and concentrations.

for the decline in the CFCs, CH_3CCl_3 and CCl_4 RFs (–0.013 W m^{-2} since 2005). The total halocarbon RF is dominated by four gases, namely CFC-12, trichlorofluoromethane (CFC-11), chlorodifluoromethane (HCFC-22) and trichlorofluoroethane (CFC-113) in that order, which account for about 85% of the total halocarbon RF (see Table 8.2) . The indirect RF from the impacts of ODSs is discussed in Section 8.3.3.2.

8.3.2.4.1 Chlorofluorocarbons and hydrochlorofluorocarbons

The CFCs and HCFCs contribute approximately 11% of the WMGHG RF. Although emissions have been drastically reduced for CFCs, their long lifetimes mean that reductions take substantial time to affect their concentrations. The RF from CFCs has declined since 2005 (mainly due to a reduction in the concentrations of CFC-11 and CFC-12), whereas the RF from HCFCs is still rising (mainly due to HCFC-22).

8.3.2.4.2 Hydrofluorocarbons

The RF of HFCs is 0.02 W m^{-2} and has close to doubled since AR4 (2005 concentrations). HFC-134a is the dominant contributor to RF of the HFCs, with an RF of 0.01 W m^{-2}.

8.3.2.4.3 Perfluorocarbons and sulphur hexafluoride

These gases have lifetimes of thousands to tens of thousands of years (Table 8.A.1); therefore emissions essentially accumulate in the atmosphere on the time scales considered here. CF_4 has a natural source and a 1750 concentration of 35 ppt (see Section 2.2.1.1.4). These gases currently contribute 0.01 W m^{-2} of the total WMGHG RF.

8.3.2.4.4 New species

Nitrogen trifluoride (NF_3) is used in the electronics industry and sulfuryl fluoride (SO_2F_2) is used as a fumigant. Both have rapidly increasing emissions and high GWPs, but currently contribute only around 0.0002 W m^{-2} and 0.0003 W m^{-2} to anthropogenic RF, respectively (Weiss et al., 2008; Andersen et al., 2009; Muhle et al., 2009; Arnold et al., 2013).

8.3.3 Ozone and Stratospheric Water Vapour

Unlike for the WMGHGs, the estimate of the tropospheric and stratospheric ozone concentration changes are almost entirely model based for the full pre-industrial to present-day interval (though, especially for the stratosphere, more robust observational evidence on changes is available for recent decades; see Section 2.2).

AR4 assessed the RF (for 1750–2005) from tropospheric ozone to be 0.35 W m^{-2} from multi-model studies with a high 95th percentile of 0.65 W m^{-2} to allow for the possibility of model overestimates of the pre-industrial tropospheric ozone levels. The stratospheric ozone RF was assessed from observational trends from 1979 to 1998 to be –0.05 ± 0.1 W m^{-2}, with the 90% confidence range increased to reflect uncertainty in the trend prior to 1979 and since 1998. In AR4 the RF from stratospheric water vapour generated by CH_4 oxidation was assessed to be +0.07 ± 0.05 W m^{-2} based on Hansen et al. (2005).

Since AR4, there have been a few individual studies of tropospheric or stratospheric ozone forcing (Shindell et al., 2006a, 2006c, 2013a; Skeie et al., 2011a; Søvde et al., 2011), a multi-model study of stratospheric ozone RF in the 2010 WMO stratospheric ozone assessment (Forster et al., 2011b), and the ACCMIP multi-model study of tropospheric and tropospheric + stratospheric chemistry models (Conley et al., 2013; Stevenson et al., 2013). There is now greater understanding of how tropospheric ozone precursors can affect stratospheric ozone, and how ODSs can affect tropospheric ozone (Shindell et al., 2013a). We assess the total ozone RF to be +0.35 (0.15 to 0.55) W m^{-2}. This can be split according to altitude or by emitted species (Shindell et al., 2013a). We assess these contributions to be 0.40 (0.20 to 0.60) W m^{-2} for ozone in the troposphere and –0.05 ± 0.10 W m^{-2} for ozone in the stratosphere based on the studies presented in Table 8.3. Alternatively, the contributions to the total ozone forcing can be attributed as 0.50 (0.30 to 0.70) W m^{-2} from ozone precursors and –0.15 (–0.3 to 0.0) W m^{-2} from the effect of ODSs. The value attributed to ODSs is assessed to be slightly smaller in magnitude than in the two studies quoted in Table 8.3 (Søvde et al., 2011; Shindell et al., 2013a) because the models used for these had stratospheric ozone RFs with higher magnitudes than the ACCMIP mean (Conley et al., 2013). Differences between the ERFs and RFs for tropospheric and stratospheric ozone are *likely* to be small compared to the uncertainties in the RFs (Shindell et al., 2013b), so the assessed values for the ERFs are the same as those for the RFs.

The influence of climate change is typically included in ozone RF estimates as those are based on modelled concentration changes, but the available literature provides insufficient evidence for the sign and magnitude of the impact and we therefore refrain from giving an estimate except to assess that it is *very likely* to be smaller than the overall uncertainty in the total RF. Unlike the WMGHGs, there are significant latitudinal variations in the RFs from changes in tropospheric and stratospheric ozone. The implications of inhomogeneous RFs are explored in more detail in Section 8.6.

There has been one study since AR4 (Myhre et al., 2007) on the RF from water vapour formed from the stratospheric oxidation of CH_4 (Section 8.3.3.3). This is consistent with the AR4 value and so has not led to any change in the recommended value of 0.07 (0.02 to 0.12) W m^{-2} since AR4.

8.3.3.1 Tropospheric Ozone

Ozone is formed in the troposphere by photochemical reactions of natural and anthropogenic precursor species (Section 8.2.3.1). Changes in ozone above the tropopause due to emissions of stratospheric ODSs can also affect ozone in the troposphere either by transport across the tropopause or modification of photolysis rates. Changes in climate have also affected tropospheric ozone concentrations (medium evidence, low agreement) through changes in chemistry, natural emissions and transport from the stratosphere (Isaksen et al., 2009).

The most recent estimates of tropospheric ozone RF come from multi-model studies under ACCMIP (Conley et al., 2013; Lamarque et al., 2013; Stevenson et al., 2013). The model ensemble reported only 1850–2000 RFs (0.34 W m^{-2}) so the single-model results from Skeie et al. (2011a) were used to expand the timespan to 1750–2010, adding 0.04 W m^{-2}, and 0.02 W m^{-2} to account for the periods 1750–1850 and 2000–2010 respectively. The best estimate of tropospheric ozone RF taking into account the ACCMIP models and the Søvde et al. (2011) results (the Skeie et al. (2011a) and Shindell et al. (2013a) models are included in ACCMIP) is 0.40 (0.20 to 0.60) W m^{-2}. The quantifiable uncertainties come from the inter-model spread (–0.11 to 0.11 W m^{-2}) and the differences between radiative transfer models (–0.07 to 0.07 W m^{-2}); all 5 to 95% confidence interval. Additional uncertainties arise from the lack of knowledge of pre-industrial emissions and the representation of chemical and physical processes beyond those included in the current models. The tropospheric ozone RF is sensitive to the assumed 'pre-industrial' levels. As described in Section 8.2.3.1, very limited late 19th and early 20th century observations of surface ozone concentrations are lower than the ACCMIP models for the same period; however, we assess that those observations are very uncertain. Skeie et al. (2011a) and Stevenson et al. (2013) increase their uncertainty ranges to 30% for 1 standard deviation which is equivalent to (–50% to +50%) for the 5 to 95% confidence range and we adopt this for AR5. The overall *confidence* in the tropospheric ozone RF is assessed as *high*.

Because we have *low confidence* in the pre-industrial ozone observations, and these were extremely limited in spatial coverage, it is not possible to calculate a purely observationally based ozone RF. However, modern observations can be used to assess the performance of the chemistry models. Bowman et al. (2013) used satellite retrievals from the TES instrument to constrain the RF from the ACCMIP models. This reduced the inter-model uncertainty by 30%; however, we still maintain overall the (–50% to +50%) 5 to 95% confidence range for AR5.

The time evolution of the tropospheric ozone forcing is shown in Figure 8.7. There is a noticeable acceleration in the forcing after 1950 and a deceleration in the 1990s reflecting the time evolution of anthropogenic precursor emissions. Observational evidence for trends in ozone concentrations is discussed in Section 2.2.2.3.

It can be useful to calculate a normalized radiative forcing (NRF) which is an RF per change in ozone column in W m^{-2} DU^{-1} or W mol^{-1}. This is only an approximation as the NRF is sensitive to the vertical profile of the ozone change and to the latitudinal profile to a smaller extent. From Table 8.3 we assess the NRF to be 0.042 (0.037 to 0.047) W m^{-2} DU^{-1} (94 (83 to 105) W mol^{-1}) similar to the value of 0.042 W m^{-2} DU^{-1} (94 W mol^{-1}) in TAR (Ramaswamy et al., 2001).

A small number of studies have looked at attributing the ozone changes among the anthropogenically emitted species. Søvde et al. (2011) report a tropospheric ozone RF of 0.38 W m^{-2}, 0.44 W m^{-2} from ozone precursors and –0.06 W m^{-2} from the impact of stratospheric ozone depletion on the troposphere. Shindell et al. (2013a) also calculate that ODSs are responsible for about –0.06 W m^{-2} of the tropospheric ozone RF, and ozone precursors for about 0.41 W m^{-2}. Six of the models in Stevenson et al. (2013) and Shindell et al. (2009) performed experiments to attribute the ozone RF to the individual precursor emissions. An average of these seven model results leads to attributions of 0.24 ± 0.13 W m^{-2} due to CH_4 emissions, 0.14 ± 0.09 W m^{-2} from NO_X emissions, 0.07 ± 0.03 W m^{-2} from CO, and 0.04 ± 0.03W m^{-2} from non-methane volatile organic compounds (NMVOCs). These results were calculated by reducing the precursor emissions individually from 2000 to pre-industrial levels. The results were scaled by the total ozone RFs attributed to ozone precursors (0.50 W m^{-2}) to give the contributions to the full 1750–2010 RF. Because of the nonlinearity of the chemistry an alternative method of starting from pre-industrial conditions and increasing precursor emissions singly may give a different result. Note that as well as inducing an ozone RF, these ozone precursor species can also strongly affect the concentrations of CH_4 and aerosols, adding extra terms (both positive and negative) to their total indirect forcings. The contributions to the 1750–2010 CH_4 RF are again based on Stevenson et al. (2013) and Shindell et al. (2009). The Stevenson et al. (2013) values are for 1850–2000 rather than 1750 to 2011 so for these we distribute the CH_4 RF for 1750–1850 and 2000–2011 (0.06 W m^{-2}) by scaling the CH_4 and CO contributions (assuming these were the most significant contributors over those time periods). This gives contributions of 0.58 ± 0.08, –0.29 ± 0.18, 0.07 ± 0.02 and 0.02 ± 0.02 W m^{-2} for changes from historical to present day emissions of CH_4 (inferred emissions), NO_x, CO and VOCs respectively (uncertainties are 5 to 95% confidence intervals). The difference between the total CH_4 RF attributed to ozone precursors here (0.38 W m^{-2}) and the value calculated from CH_4 concentration changes in Table 8.2 (0.48 W m^{-2}) is due to nonlinearities in the CH_4 chemistry because large single-step changes were used. To allow an easier comparison between the concentration-based and emission-based approaches in Section 8.5.1 the nonlinear term (+0.1 W m^{-2}) is distributed between the four emitted species according to their absolute magnitude so that they total 0.48 W m^{-2}. The scaled results still lie within the uncertainty bounds of the values quoted above. The impact of climate change over the historical period on CH_4 oxidation is not accounted for in these calculations.

Tropospheric ozone can also affect the natural uptake of CO_2 by decreasing plant productivity (see Sections 6.4.8.2 and 8.2.3.1) and it is found that this indirect effect could have contributed to the total CO_2 RF (Section 8.3.2.1; Sitch et al., 2007), roughly doubling the overall RF attributed to ozone precursors. Although we assess there to be

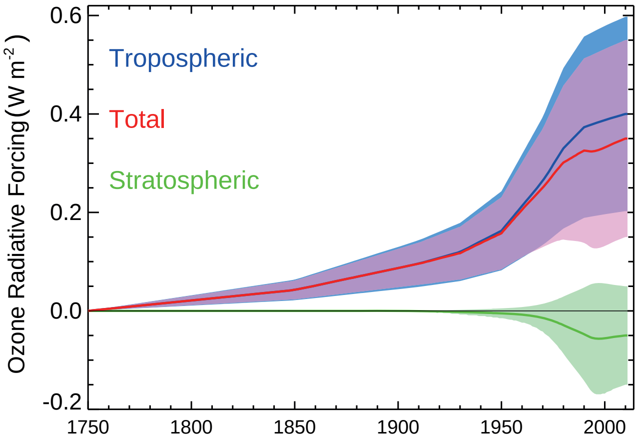


Figure 8.7 | Time evolution of the radiative forcing from tropospheric and stratospheric ozone from 1750 to 2010. Tropospheric ozone data are from Stevenson et al. (2013) scaled to give 0.40 W m^{-2} at 2010. The stratospheric ozone RF follow the functional shape of the Effective Equivalent Stratospheric Chlorine assuming a 3-year age of air (Daniel et al., 2010) scaled to give –0.05 W m^{-2} at 2010.

Table 8.3 | Contributions of tropospheric and stratospheric ozone changes to radiative forcing (W m^{-2}) from 1750 to 2011.

	Troposphere				Stratosphere		
	Longwave	**Shortwave**	**Total**	**Normalized Radiative Forcing m W m^{-2} DU^{-1}**	**Longwave**	**Shortwave**	**Total**
AR4 (Forster et al. (2007)			0.35 (0.25 to 0.65)				–0.05 (–0.15 to 0.05)
Shindell et al. (2013a)[f]			0.33 (0.31 to 0.35)				–0.08 (–0.10 to –0.06)
WMO (Forster et al., 2011b)							–0.03[a] (–0.23 to +0.17) +0.03[b]
Søvde et al. (2011)			0.45[c] 0.38[d]	40 39			–0.12 –0.12
Skeie et al. (2011a)			0.41 (0.21 to 0.61)	38			
ACCMIP[e]	0.33 (0.24 to 0.42)	0.08 (0.06 to 0.10)	0.41 (0.21 to 0.61)	42 (37 to 47)	–0.13 (–0.26 to 0)	0.11 (0.03 to 0.19)	–0.02 (–0.09 to 0.05)
AR5			0.40 (0.20 to 0.60)	42 (37 to 47)			–0.05 (-0.15 to 0.05)

Notes:

[a] From multi-model results.

[b] From Randel and Wu (2007) observation-based data set.

[c] Using the REF chemistry, see Søvde et al. (2011).

[d] Using the R2 chemistry.

[e] The Atmospheric Chemistry and Climate Model Intercomparison Project (ACCMIP) tropospheric ozone RFs are from Stevenson et al. (2013). The stratospheric ozone values are from Conley et al. (2013) calculations for 1850–2005 disregarding the Modèle de Chimie Atmosphérique a Grande Echelle (MOCAGE) model which showed excessive ozone depletion.

[f] Only the Goddard Institute for Space Studies (GISS)-E2-R results (including bias correction) from the Shindell et al. (2013a) study are shown here rather than the multi-model result presented in that paper.

robust evidence of an effect, we make no assessment of the magnitude because of lack of further corroborating studies.

8.3.3.2 Stratospheric Ozone

The decreases in stratospheric ozone due to anthropogenic emissions of ODSs have a positive RF in the shortwave (increasing the flux into the troposphere) and a negative RF in the longwave. This leaves a residual forcing that is the difference of two larger terms. In the lower stratosphere the longwave effect tends to be larger, whereas in the upper stratosphere the shortwave dominates. Thus whether stratospheric ozone depletion has contributed an overall net positive or negative forcing depends on the vertical profile of the change (Forster and Shine, 1997). WMO (2011) assessed the RF from 1979 to 2005 from observed ozone changes (Randel and Wu, 2007) and results from 16 models for the 1970s average to 2004. The observed and modelled mean ozone changes gave RF values of different signs (see Table 8.3). Negative net RFs arise from models with ozone decline in the lowermost stratosphere, particularly at or near the tropopause.

The ACCMIP study also included some models with stratospheric chemistry (Conley et al., 2013). One model in that study stood out as having excessive ozone depletion. Removing that model leaves a stratospheric ozone RF of –0.02 (–0.09 to 0.05) W m^{-2}. These results are in good agreement with the model studies from WMO (2011). Forster et al. (2007) in AR4 calculated a forcing of –0.05 W m^{-2} from observations over the period 1979–1998 and increased the uncertainty to 0.10 W m^{-2} to encompass changes between the pre-industrial period and 2005. The RF from stratospheric ozone due to changes in emissions of ozone precursors and ODSs is here assessed to be –0.05 (–0.15 to 0.05) taking into account all the studies listed in Table 8.3. This is in agreement with AR4, although derived from different data. The time-line of stratospheric ozone forcing is shown in Figure 8.7, making the assumption that it follows the trajectory of the changes in EESC. It reaches a minimum in the late 1990s and starts to recover after that.

The net global RF from ODSs taking into account the compensating effects on ozone and their direct effects as WMGHGs is 0.18 (0.03 to 0.33) W m^{-2}. The patterns of RF for these two effects are different so the small net global RF comprises areas of positive and negative RF.

8.3.3.3 Stratospheric Water Vapour

Stratospheric water vapour is dependent on the amount entering from the tropical troposphere and from direct injection by volcanic plumes (Joshi and Jones, 2009) and aircraft, and the *in situ* chemical production from the oxidation of CH_4 and hydrogen. This contrasts with tropospheric water vapour which is almost entirely controlled by the balance between evaporation and precipitation (see FAQ 8.1). We consider trends in the transport (for instance, due to the Brewer–Dobson circulation or tropopause temperature changes) to be climate feedback rather than a forcing so the anthropogenic RFs come from oxidation of CH_4 and hydrogen, and emissions from stratospheric aircraft.

Myhre et al. (2007) used observations of the vertical profile of CH_4 to deduce a contribution from oxidation of anthropogenic CH_4 of 0.083

W m^{-2} which compares with the value of 0.07 W m^{-2} from calculations in a 2D model in Hansen et al. (2005). Both of these values are consistent with AR4 which obtained the stratospheric water vapour forcing by scaling the CH_4 direct forcing by 15%. Thus the time evolution of this forcing is also obtained by scaling the CH_4 forcing by 15%. The best estimate and uncertainty range from AR4 of 0.07 (0.02 to 0.12) W m^{-2} remain unchanged and the large uncertainty range is due to large differences found in the intercomparison studies of radiative transfer modelling for changes in stratospheric water vapour (see Section 8.3.1).

RF from the current aircraft fleet through stratospheric water vapour emissions is very small. Wilcox et al. (2012) estimate a contribution from civilian aircraft in 2005 of 0.0009 (0.0003 to 0.0013) W m^{-2} with *high confidence* in the upper limit. Water vapour emissions from aircraft in the troposphere also contribute to contrails which are discussed in Section 8.3.4.5.

8.3.4 Aerosols and Cloud Effects

8.3.4.1 Introduction and Summary of AR4

In AR4 (Forster et al., 2007), RF estimates were provided for three aerosol effects. These were the RF of aerosol–radiation interaction (previously denoted as direct aerosol effect), RF of the aerosol–cloud interaction (previously denoted as the cloud albedo effect), and the impact of BC on snow and ice surface albedo. See Chapter 7 and Figure 7.3 for an explanation of the change in terminology between AR4 and AR5. The RF due to aerosol–radiation interaction is scattering and absorption of shortwave and longwave radiation by atmospheric aerosols. Several different aerosol types from various sources are present in the atmosphere (see Section 8.2). Most of the aerosols primarily scatter solar radiation, but some components absorb solar radiation to various extents with BC as the most absorbing component. RF of aerosols in the troposphere is often calculated at the TOA because it is similar to tropopause values (Forster et al., 2007). A best estimate RF of –0.5 ± 0.4 W m^{-2} was given in AR4 for the change in the net aerosol–radiation interaction between 1750 and 2005 and a medium to low level of scientific understanding (LOSU).

An increase in the hygroscopic aerosol abundance may enhance the concentration of cloud condensation nuclei (CCN). This may increase the cloud albedo and under the assumption of fixed cloud water content this effect was given a best estimate of –0.7 W m^{-2} (range from –1.8 to –0.3) in AR4 and a low LOSU.

BC in the snow or ice can lead to a decrease of the surface albedo. This leads to a positive RF. In AR4 this mechanism was given a best RF estimate of 0.1 ± 0.1 W m^{-2} and a low LOSU.

Impacts on clouds from the ERF of aerosol–cloud interaction (including both effects previously denoted as cloud lifetime and cloud albedo effect) and the ERF of aerosol–radiation interaction (including both effects previously denoted as direct aerosol effect and semi-direct effect) were not strictly in accordance with the RF concept, because they involve tropospheric changes in variables other than the forcing agent at least in the available model estimates, so no best RF estimates were provided in AR4 (see Section 8.1). However, the ERF of aerosol–cloud and aerosol–radiation interactions were included in the discussion of total aerosol effect in Chapter 7 in AR4 (Denman et al., 2007). The mechanisms influenced by anthropogenic aerosol including the aerosol cloud interactions are discussed in detail in this assessment in Section 7.5 and summarized in the subsections that follow.

8.3.4.2 Radiation Forcing of the Aerosol–Radiation Interaction by Component

Based on a combination of global aerosol models and observation-based methods, the best RF estimate of the aerosol–radiation interaction in AR5 is –0.35 (–0.85 to +0.15) W m^{-2} (see Section 7.5). This estimate is thus smaller in magnitude than in AR4, however; with larger uncertainty range. Overall, the estimate compared to AR4 is more robust because the agreement between estimates from models and observation-based methods is much greater (see Section 7.5). The larger range arises primarily from analysis by observation-based methods (see Section 7.5).

The main source of the model estimate is based on updated simulations in AeroCom (Myhre et al., 2013), which is an intercomparison exercise of a large set of global aerosol models that includes extensive evaluation against measurements. The assessment in Chapter 7 relies to a large extent on this study for the separation in the various aerosol components, except for BC where the assessment in Chapter 7 relies in addition on Bond et al. (2013). The RF of aerosol–radiation interaction is separated into seven components in this report; namely sulphate, BC from fossil fuel and biofuel, OA from fossil fuel and biofuel, BC and OA combined from biomass burning (BB), nitrate, SOA and mineral dust. BC and OA from biomass burning are combined due to the joint sources, whereas treated separately for fossil fuel and biofuel because there is larger variability in the ratio of BC to OA in the fossil fuel and biofuel emissions. This approach is consistent with TAR and AR4. Table 8.4 compares the best estimates of RF due to aerosol–radiation interaction for various components in this report with values in SAR, TAR and AR4. In magnitude the sulphate and BC from use of fossil fuel and biofuel dominate. It is important to note that the BB RF is small in magnitude but consists of larger, offsetting terms in magnitude from OA and BC (see Section 7.5.2). Changes in the estimates of RF due to aerosol–radiation interaction of the various components have been rather modest compared to AR4, except for BC from fossil fuel and biofuel (see Section 7.5). SOA is a new component compared to AR4. Anthropogenic SOA precursors contribute only modestly to the anthropogenic change in SOA. The increase in SOA is mostly from biogenic precursors and enhanced partitioning of SOA into existing particles from anthropogenic sources and changes in the atmospheric oxidation (Carlton et al., 2010). This change in SOA is therefore of anthropogenic origin, but natural emission of SOA precursors is important (Hoyle et al., 2011).

Note that the best estimate and the uncertainty for the total is not equal to the sum of the aerosol components because the total is estimated based on a combination of methods (models and observation-based methods), whereas the estimates for the components rely mostly on model estimates.

Table 8.4 | Global and annual mean RF ($W\ m^{-2}$) due to aerosol–radiation interaction between 1750 and 2011 of seven aerosol components for AR5. Values and uncertainties from SAR, TAR, AR4 and AR5 are provided when available. Note that for SAR, TAR and AR4 the end year is somewhat different than for AR5 with 1993, 1998 and 2005, respectively.

	Global Mean Radiative Forcing ($W\ m^{-2}$)			
	SAR	**TAR**	**AR4**	**AR5**
Sulphate aerosol	–0.40 (–0.80 to –0.20)	–0.40 (–0.80 to –0.20)	–0.40 (–0.60 to –0.20)	–0.40 (–0.60 to –0.20)
Black carbon aerosol from fossil fuel and biofuel	+0.10 (+0.03 to +0.30)	+0.20 (+0.10 to +0.40)	+0.20 (+0.05 to +0.35)	+0.40 (+0.05 to +0.80)
Primary organic aerosol from fossil fuel and biofuel	Not estimated	–0.10 (–0.30 to –0.03)	–0.05 (0.00 to –0.10)	–0.09 (–0.16 to –0.03)
Biomass burning	–0.20 (–0.60 to –0.07)	–0.20 (–0.60 to –0.07)	+0.03(–0.09 to +0.15)	–0.0 (–0.20 to +0.20)
Secondary organic aerosol	Not estimated	Not estimated	Not estimated	–0.03 (–0.27 to +0.20)
Nitrate	Not estimated	Not estimated	–0.10 (–0.20 to 0.00)	–0.11 (–0.30 to –0.03)
Dust	Not estimated	–0.60 to +0.40	–0.10 (–0.30 to +0.10)	–0.10 (–0.30 to +0.10)
Total	Not estimated	Not estimated	–0.50 (–0.90 to –0.10)	–0.35 (–0.85 to +0.15)

The RF due to aerosol–radiation interaction during some time periods is more uncertain than the current RF. Improvements in the observations of aerosols have been substantial with availability of remote sensing from the ground-based optical observational network AErosol RObotic NETwork (AERONET) and the launch of the Moderate Resolution Imaging Spectrometer (MODIS) and Multi-angle Imaging Spectro-Radiometer (MISR) instruments (starting in 2000) as well as other satellite data. This has contributed to constraining the current RF using aerosol observations. The aerosol observations are very limited backward in time, although there is growing constraint coming from new ice and lake core records, and uncertainties in the historical emission of aerosols and their precursors used in the global aerosol modeling are larger than for current conditions. Emissions of carbonaceous aerosols are particularly uncertain in the 1800s due to a significant biofuel source in this period, in contrast to the SO_2 emissions which were very small until the end of the 1800s. The uncertainty in the biomass burning emissions also increases backward in time. Note that, for 1850, the biomass burning emissions from Lamarque et al. (2010) are quite different from the previous estimates, but RF due to aerosol–radiation interaction is close to zero for this component. Figure 8.8 shows an example of the time evolution of the RF due to aerosol–radiation interaction as a total and separated into six aerosol components. From 1950 to 1990 there was a strengthening of the total RF due to aerosol–radiation interaction, mainly due to a strong enhancement of the sulphate RF. After 1990 the change has been small with even a weakening of the RF due to aerosol–radiation interaction, mainly due to a stronger BC RF as a result of increased emissions in East and Southeast Asia.

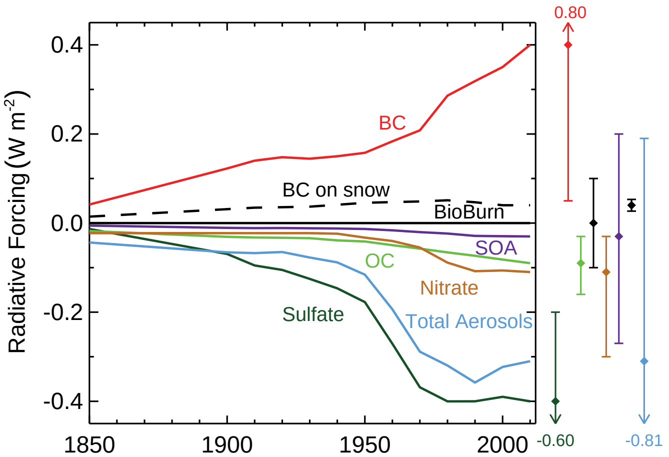


Figure 8.8 | Time evolution of RF due to aerosol–radiation interaction and BC on snow and ice. Multi-model results for 1850, 1930, 1980 and 2000 from ACCMIP for aerosol–radiation interaction (Shindell et al., 2013c) and BC on snow and ice (Lee et al., 2013) are combined with higher temporal-resolution results from the Goddard Institute for Space Studies (GISS)-E2 and Oslo-Chemical Transport Model 2 (OsloCTM2) models (aerosol–radiation interaction) and OsloCTM2 (BC on snow and ice). Uncertainty ranges (5 to 95%) for year 2010 are shown with vertical lines. Values next to the uncertainty lines are for cases where uncertainties go beyond the scale. The total includes the RF due to aerosol–radiation interaction for six aerosol components and RF due to BC on snow and ice. All values have been scaled to the best estimates for 2011 given in Table 8.4. Note that time evolution for mineral dust is not included and the total RF due to aerosol–radiation interaction is estimated based on simulations of the six other aerosol components.

8.3.4.3 Aerosol–Cloud Interactions

The RF by aerosol effects on cloud albedo was previously referred to as the Twomey or cloud albedo effect (see Section 7.1). Although this RF can be calculated, no estimate of this forcing is given because it has heuristic value only and does not simply translate to the ERF due to aerosol–cloud interaction. The total aerosol ERF, namely ERF due to aerosol–radiation and aerosol–cloud interactions (excluding BC on snow and ice) provided in Chapter 7 is estimated with a 5 to 95% uncertainty between –1.9 and –0.1 $W\ m^{-2}$ with a best estimate value of –0.9 $W\ m^{-2}$ (*medium confidence*). The *likely* range of this forcing is between –1.5 and –0.4 $W\ m^{-2}$. The estimate of ERF due to aerosol–radiation and aerosol-cloud interaction is lower (i.e., less negative) than the corresponding AR4 RF estimate of –1.2 $W\ m^{-2}$ because the latter was based mainly on GCM studies that did not take secondary processes (such as aerosol effects on mixed-phase and/or convective clouds and effects on longwave radiation) into account. This new best estimate of ERF due to aerosol–radiation and aerosol–cloud interaction is also consistent with the studies allowing cloud-scale processes and related responses and with the lower estimates of this forcing inferred from satellite observations.

Frequently Asked Questions

FAQ 8.2 | Do Improvements in Air Quality Have an Effect on Climate Change?

Yes they do, but depending on which pollutant(s) they limit, they can either cool or warm the climate. For example, whereas a reduction in sulphur dioxide (SO_2) emissions leads to more warming, nitrogen oxide (NO_x) emission control has both a cooling (through reducing of tropospheric ozone) and a warming effect (due to its impact on methane lifetime and aerosol production). Air pollution can also affect precipitation patterns.

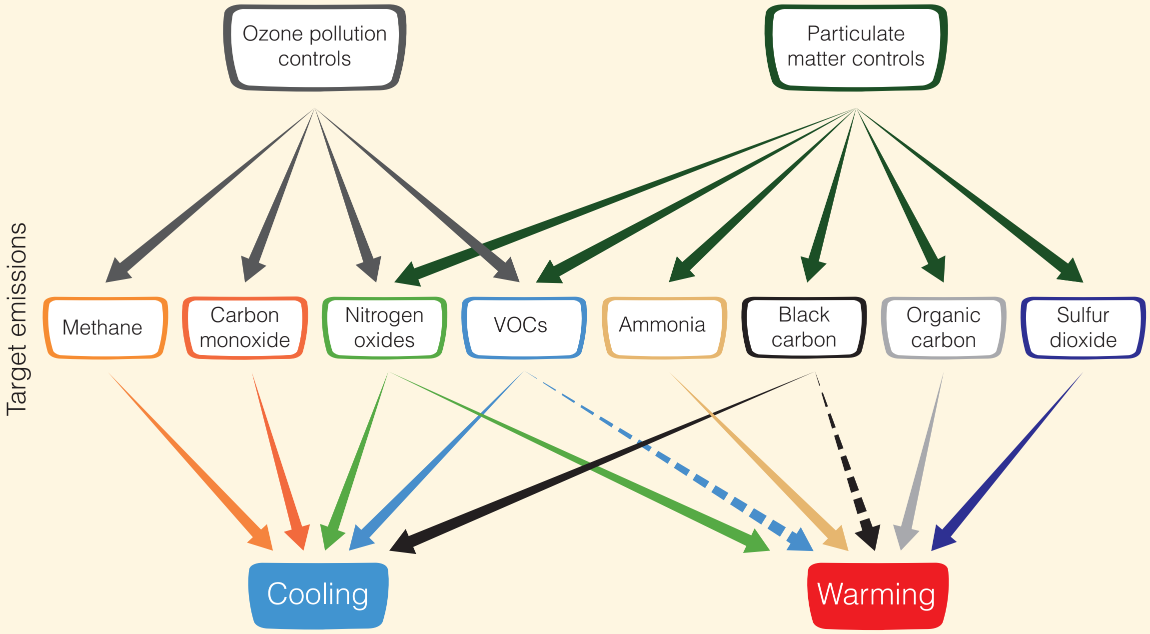
Air quality is nominally a measure of airborne surface pollutants, such as ozone, carbon monoxide, NO_x and aerosols (solid or liquid particulate matter). Exposure to such pollutants exacerbates respiratory and cardiovascular diseases, harms plants and damages buildings. For these reasons, most major urban centres try to control discharges of airborne pollutants.

Unlike carbon dioxide (CO_2) and other well-mixed greenhouse gases, tropospheric ozone and aerosols may last in the atmosphere only for a few days to a few weeks, though indirect couplings within the Earth system can prolong their impact. These pollutants are usually most potent near their area of emission or formation, where they can force local or regional perturbations to climate, even if their globally averaged effect is small.

Air pollutants affect climate differently according to their physical and chemical characteristics. Pollution-generated greenhouse gases will impact climate primarily through shortwave and longwave radiation, while aerosols can in addition affect climate through cloud–aerosol interactions.

Controls on anthropogenic emissions of methane (FAQ 8.2, Figure 1) to lower surface ozone have been identified as 'win–win' situations. Consequences of controlling other ozone precursors are not always as clear. NO_x emission controls, for instance, might be expected to have a cooling effect as they reduce tropospheric ozone, but their impact on CH_4 lifetime and aerosol formation is more likely instead to cause overall warming.

Satellite observations have identified increasing atmospheric concentrations of SO_2 (the primary precursor to scattering sulphate aerosols) from coal-burning power plants over eastern Asia during the last few decades. The most recent power plants use scrubbers to reduce such emissions (albeit not the concurrent CO_2 emissions and associated long-term climate warming). This improves air quality, but also reduces the cooling effect of sulphate aerosols and therefore exacerbates warming. Aerosol cooling occurs through aerosol–radiation and aerosol–cloud interactions and is estimated at -0.9 W m^{-2} (all aerosols combined, Section 8.3.4.3) since pre-industrial, having grown especially during the second half of the 20th century when anthropogenic emissions rose sharply. *(continued on next page)*



FAQ 8.2, Figure 1 | Schematic diagram of the impact of pollution controls on specific emissions and climate impact. Solid black line indicates known impact; dashed line indicates uncertain impact.

FAQ 8.2 (continued)

Black carbon or soot, on the other hand, absorbs heat in the atmosphere (leading to a 0.4 W m^{-2} radiative forcing from anthropogenic fossil and biofuel emissions) and, when deposited on snow, reduces its albedo, or ability to reflect sunlight. Reductions of black carbon emissions can therefore have a cooling effect, but the additional interaction of black carbon with clouds is uncertain and could lead to some counteracting warming.

Air quality controls might also target a specific anthropogenic activity sector, such as transportation or energy production. In that case, co-emitted species within the targeted sector lead to a complex mix of chemistry and climate perturbations. For example, smoke from biofuel combustion contains a mixture of both absorbing and scattering particles as well as ozone precursors, for which the combined climate impact can be difficult to ascertain.

Thus, surface air quality controls will have some consequences on climate. Some couplings between the targeted emissions and climate are still poorly understood or identified, including the effects of air pollutants on precipitation patterns, making it difficult to fully quantify these consequences. There is an important twist, too, in the potential effect of climate change on air quality. In particular, an observed correlation between surface ozone and temperature in polluted regions indicates that higher temperatures from climate change alone could worsen summertime pollution, suggesting a 'climate penalty'. This penalty implies stricter surface ozone controls will be required to achieve a specific target. In addition, projected changes in the frequency and duration of stagnation events could impact air quality conditions. These features will be regionally variable and difficult to assess, but better understanding, quantification and modelling of these processes will clarify the overall interaction between air pollutants and climate.

One reason an expert judgment estimate of ERF due to aerosol–radiation and aerosol–cloud interaction is provided rather than ERF due to aerosol–cloud interaction specifically is that the individual contributions are very difficult to disentangle. These contributions are the response of processes that are the outputs from a system that is constantly readjusting to multiple nonlinear forcings. Assumptions of independence and linearity are required to deduce ERF due to aerosol–radiation interaction and ERF due to aerosol–cloud interaction (although there is no *a priori* reason why the individual ERFs should be simply additive). Under these assumptions, ERF due to aerosol–cloud interaction is deduced as the difference between ERF due to aerosol–radiation and aerosol–cloud interaction and ERF due to aerosol–radiation interaction alone. This yields an ERF due to aerosol–cloud interaction estimate of –0.45 W m^{-2} which is much smaller in magnitude than the –1.4 W m^{-2} median forcing value of the models summarized in Figure 7.19 and is also smaller in magnitude than the AR4 estimates of –0.7 W m^{-2} for RF due to aerosol–cloud interaction.

8.3.4.4 Black Carbon Deposition in Snow and Ice

Because absorption by ice is very weak at visible and ultraviolet (UV) wavelengths, BC in snow makes the snow darker and increases absorption. This is not enough darkening to be seen by eye, but it is enough to be important for climate (Warren and Wiscombe, 1980; Clarke and Noone, 1985). Several studies since AR4 have re-examined this issue and find that the RF may be weaker than the estimates of Hansen and Nazarenko (2004) in AR4 (Flanner et al., 2007; Koch et al., 2009a; Rypdal et al., 2009; Lee et al., 2013). The anthropogenic BC on snow/ice is assessed to have a positive global and annual mean RF of +0.04 W m^{-2}, with a 0.02–0.09 W m^{-2} 5 to 95% uncertainty range (see further description in Section 7.5.2.3). This RF has a two to four times larger global mean surface temperature change per unit forcing than a change in CO_2.

In Figure 8.8, the time evolution of global mean RF due to BC on snow and ice is shown based on multi-model simulations in ACCMIP (Lee et al., 2013) for 1850, 1930, 1980 and 2000. The results show a maximum in the RF in 1980 with a small increase since 1850 and a 20% lower RF in 2000 compared to 1980. Those results are supported by observations. The BC concentration in the Arctic atmosphere is observed to be declining since 1990, at least in the Western Hemisphere portion (Sharma et al., 2004), which should lead to less deposition of BC on the snow surface. Surveys across Arctic during 1998 and 2005 to 2009 showed that the BC content of Arctic snow appears to be lower than in 1984 (Doherty et al., 2010) and found BC concentrations in Canada, Alaska and the Arctic Ocean (e.g., Hegg et al., 2009), about a factor of 2 lower than measured in the 1980s (e.g., Clarke and Noone, 1985). Large-area field campaigns (Huang et al., 2011; Ye et al., 2012) found that the BC content of snow in northeast China is comparable to values found in Europe. The steep drop off in BC content of snow with latitude in northeast China may indicate that there is not much BC in the Arctic coming from China (Huang et al., 2011; Ye et al., 2012; Wang et al., 2013). The change in the spatial pattern of emission of BC is a main cause for the difference in the temporal development of RF due to BC on snow and ice compared to the BC from RF due to aerosol–radiation interaction over the last decades.

8.3.4.5 Contrails and Contrail-Induced Cirrus

AR4 assessed the RF of contrails (persistent linear contrails) as +0.01 (–0.007 to +0.02) W m^{-2} and provided no estimate for contrail induced cirrus. In AR5, Chapter 7 gives a best estimate of RF due to contrails of +0.01 (+0.005 to +0.03) W m^{-2} and an ERF estimate of the combined contrails and contrail-induced cirrus of +0.05 (+0.02 to +0.15) W m^{-2}. Since AR4, the evidence for contrail-induced cirrus has increased because of observational studies (for further details see Section 7.2.7).

8.3.5 Land Surface Changes

8.3.5.1 Introduction

Anthropogenic land cover change has a direct impact on the Earth radiation budget through a change in the surface albedo. It also impacts the climate through modifications in the surface roughness, latent heat flux and river runoff. In addition, human activity may change the water cycle through irrigation and power plant cooling, and also generate direct input of heat to the atmosphere by consuming energy. Land use change, and in particular deforestation, also has significant impacts on WMGHG concentration, which are discussed in Section 6.3.2.2. Potential geo-engineering techniques that aim at increasing the surface albedo are discussed in Section 7.7.2.3.

AR4 referenced a large number of RF estimates resulting from a change in land cover albedo. It discussed the uncertainties due to the reconstruction of historical vegetation, the characterization of present-day vegetation and the surface radiation processes. On this basis, AR4 gave a best estimate of RF relative to 1750 due to land use related surface albedo at –0.2 ± 0.2 W m^{-2} with a level of scientific understanding at medium-low.

8.3.5.2 Land Cover Changes

Hurtt et al. (2006) estimates that 42 to 68% of the global land surface was impacted by land use activities (crop, pasture, wood harvest) during the 1700–2000 period. Until the mid-20th century most land use change took place over the temperate regions of the NH. Since then, reforestation is observed in Western Europe, North America and China as a result of land abandonment and afforestation efforts, while deforestation is concentrated in the tropics. After a rapid increase of the rate of deforestation during the 1980s and 1990s, satellite data indicate a slowdown in the past decade (FAO, 2012).

Since AR4, Pongratz et al. (2008) and Kaplan et al. (2011) extended existing reconstructions on land use back in time to the past millennium, accounting for the progress of agriculture technique and historical events such as the black death or war invasions. As agriculture was already widespread over Europe and South Asia by 1750, the RF, which is defined with respect to this date, is weaker than the radiative flux change from the state of natural vegetation cover (see Figure 8.9). Deforestation in Europe and Asia during the last millennium led to a significant regional negative forcing. Betts et al. (2007) and Goosse et al. (2006) argue that it probably contributed to the 'Little Ice Age', together with natural solar and volcanic activity components, before the increase in GHG concentration led to temperatures similar to those experienced in the early part of the second millennium. There is still significant uncertainty in the anthropogenic land cover change, and in particular its time evolution (Gaillard et al., 2010).

8.3.5.3 Surface Albedo and Radiative Forcing

Surface albedo is the ratio between reflected and incident solar flux at the surface. It varies with the surface cover. Most forests are darker (i.e., lower albedo) than grasses and croplands, which are darker than barren land and desert. As a consequence, deforestation tends to increase the Earth albedo (negative RF) while cultivation of some bright surfaces may have the opposite effect. Deforestation also leads to a large increase in surface albedo in case of snow cover as low vegetation accumulates continuous snow cover more readily in early winter allowing it to persist longer in spring. This causes average winter albedo in deforested areas to be generally much higher than that of a tree-covered landscape (Bernier et al., 2011).

The pre-industrial impact of the Earth albedo increase due to land use change, including the reduced snow masking by tall vegetation, is estimated to be on the order of –0.05 W m^{-2} (Pongratz et al., 2009). Since then, the increase in world population and agriculture development led to additional forcing. Based on reconstruction of land use since the beginning of the Industrial Era, Betts et al. (2007) and Pongratz et al. (2009) computed spatially and temporally distributed estimates of the land use RF. They estimate that the shortwave flux change induced by the albedo variation, from fully natural vegetation state to 1992, is on the order of –0.2 W m^{-2} (range –0.24 to –0.21W m^{-2}). The RF, defined with respect to 1750, is in the range –0.17 to –0.18 W m^{-2}. A slightly stronger value (–0.22 W m^{-2}) was found by Davin et al. (2007) for the period 1860–1992.

In recent years, the availability of global scale MODIS data (Schaaf et al., 2002) has improved surface albedo estimates (Rechid et al., 2009). These data have been used by Myhre et al (2005a) and Kvalevag et al. (2010). They argue that the observed albedo difference between natural vegetation and croplands is less than usually assumed in climate simulations, so that the RF due to land use change is weaker than in estimates that do not use the satellite data. On the other hand, Nair et al. (2007) show observational evidence of an underestimate of the surface albedo change in land use analysis in southwest Australia. Overall, there is still a significant range of RF estimates for the albedo component of land use forcing. This is mostly due to the range of albedo change as a result of land use change, as shown in an inter-comparison of seven atmosphere–land models (de Noblet-Ducoudre et al., 2012).

Deforestation has a direct impact on the atmospheric CO_2 concentration and therefore contributes to the WMGHG RF as quantified in Section 8.3.2. Conversely, afforestation is a climate mitigation strategy to limit the CO_2 concentration increase. Several authors have compared the radiative impact of deforestation/afforestation that results from the albedo change with the greenhouse effect of CO_2 released/sequestered. Pongratz et al. (2010) shows that the historic land use change has had a warming impact (i.e., greenhouse effect dominates) at the global scale and over most regions with the exception of Europe and India. Bala et al. (2007) results show latitudinal contrast where the greenhouse effect dominates for low-latitude deforestation while

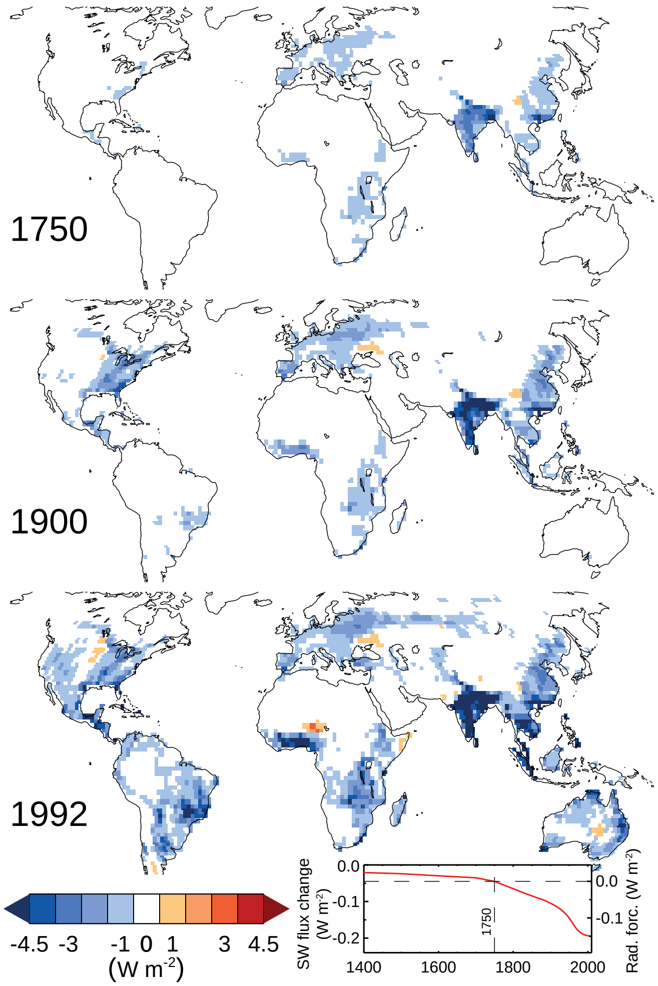


Figure 8.9 | Change in top of the atmosphere (TOA) shortwave (SW) flux (W m^{-2}) following the change in albedo as a result of anthropogenic Land Use Change for three periods (1750, 1900 and 1992 from top to bottom). By definition, the RF is with respect to 1750, but some anthropogenic changes had already occurred in 1750. The lower right inset shows the globally averaged impact of the surface albedo change to the TOA SW flux (left scale) as well as the corresponding RF (right scale) after normalization to the 1750 value. Based on simulations by Pongratz et al. (2009).

the combined effect of albedo and evapotranspiration impact does at high latitude. These results are also supported by Bathiany et al. (2010). Similarly, Lohila et al. (2010) shows that the afforestation of boreal peatlands results in a balanced RF between the albedo and greenhouse effect. Overall, because of the opposite impacts, the potential of afforestation to mitigate climate change is limited (Arora and Montenegro, 2011) while it may have undesired impacts on the atmospheric circulation, shifting precipitation patterns (Swann et al., 2012).

8.3.5.4 Other Impacts of Land Cover Change on the Earth's Albedo

Burn scars resulting from agriculture practices, uncontrolled fires or deforestation (Bowman et al., 2009) have a lower albedo than unperturbed vegetation (Jin and Roy, 2005). On the other hand, at high latitude, burnt areas are more easily covered by snow, which may result in an overall increase of the surface albedo. Surface blackening of natural vegetation due to fire is relatively short lived and typically disappears within one to a few years (Jin et al., 2012). Myhre et al. (2005b) estimates a global albedo-related radiative effect due to African fires of 0.015 W m^{-2}.

Over semi-arid areas, the development of agriculture favours the generation of dust. Mulitza et al. (2010) demonstrates a very large increase of dust emission and deposition in the Sahel concomitant with the development of agriculture in this area. This, together with the analysis of dust sources (Ginoux et al., 2010), suggests that a significant fraction of the dust that is transported over the Atlantic has an anthropogenic origin and impacts the Earth albedo. There is no full estimate of the resulting RF, however. The dust RF estimate in Section 8.3.4.2 includes both land use contributions and change in wind-driven emissions. Both dust and biomass burning aerosol may impact the Earth surface albedo as these particles can be deposed on snow, which has a large impact on its absorption, in particular for soot. This is discussed in Section 8.3.4.4.

Urban areas have an albedo that is 0.01 to 0.02 smaller than adjacent croplands (Jin et al., 2005). There is the potential for a strong increase through white roof coating with the objective of mitigating the heat island effect (Oleson et al., 2010). Although the global scale impact is small, local effects can be very large, as shown by Campra et al. (2008) that reports a regional (260 km^2) 0.09 increase in albedo and –20 W m^{-2} RF as a consequence of greenhouse horticulture development.

8.3.5.5 Impacts of Surface Change on Climate

Davin et al. (2007) argues that the climate sensitivity to land use forcing is lower than that for other forcings, due to its spatial distribution but also the role of non-radiative processes. Indeed, in addition to the impact on the surface albedo, land use change also modifies the evaporation and surface roughness, with counterbalancing consequences on the lower atmosphere temperature. There is increasing evidence that the impact of land use on evapotranspiration—a non-RF on climate—is comparable to, but of opposite sign than, the albedo effect, so that RF is not as useful a metric as it is for gases and aerosols. For instance, Findell et al. (2007) climate simulations show a negligible impact of land use change on the global mean temperature, although there are some significant regional changes.

Numerical climate experiments demonstrate that the impact of land use on climate is much more complex than just the RF. This is due in part to the very heterogeneous nature of land use change (Barnes and Roy, 2008), but mostly due to the impact on the hydrological cycle through evapotranspiration, root depth and cloudiness (van der Molen et al., 2011). As a consequence, the forcing on climate is not purely radiative and the net impact on the surface temperature may be either positive or negative depending on the latitude (Bala et al., 2007). Davin and de Noblet-Ducoudre (2010) analyses the impact on climate of large-scale deforestation; the albedo cooling effect dominates for high latitude whereas reduced evapotranspiration dominates in the tropics. This latitudinal trend is confirmed by observations of the temperature difference between open land and nearby forested land (Lee et al., 2011).

Irrigated areas have continuously increased during the 20th century although a slowdown has been observed in recent decades (Bonfils and Lobell, 2007). There is clear evidence that irrigation leads to local cooling of several degrees (Kueppers et al., 2007). Irrigation also affects cloudiness and precipitation (Puma and Cook, 2010). In the United States, DeAngelis et al. (2010) found that irrigation in the Great Plains in the summer produced enhanced precipitation in the Midwest 1000 km to the northeast.

8.3.5.6 Conclusions

There is still a rather wide range of estimates of the albedo change due to anthropogenic land use change, and its RF. Although most published studies provide an estimate close to –0.2 W m^{-2}, there is convincing evidence that it may be somewhat weaker as the albedo difference between natural and anthropogenic land cover may have been overestimated. In addition, non-radiative impact of land use have a similar magnitude, and may be of opposite sign, as the albedo effect (though these are not part of RF). A comparison of the impact of land use change according to seven climate models showed a wide range of results (Pitman et al., 2009), partly due to difference in the implementation of land cover change, but mostly due to different assumptions on ecosystem albedo, plant phenology and evapotranspiration. There is no agreement on the sign of the temperature change induced by anthropogenic land use change. It is *very likely* that land use change led to an increase of the Earth albedo with a RF of –0.15 ± 0.10 W m^{-2}, but a net cooling of the surface—accounting for processes that are not limited to the albedo—is *about as likely as not*.

8.4 Natural Radiative Forcing Changes: Solar and Volcanic

Several natural drivers of climate change operate on multiple time scales. Solar variability takes place at many time scales that include centennial and millennial scales (Helama et al., 2010), as the radiant energy output of the Sun changes. Also, variations in the astronomical alignment of the Sun and the Earth (Milankovitch cycles) induce cyclical changes in RF, but this is substantial only at millennial and longer time scales (see Section 5.2.1.1). Volcanic forcing is highly episodic, but can have dramatic, rapid impacts on climate. No major asteroid impacts occurred during the reference period (1750–2012) and thus this effect is not considered here. This section discusses solar and volcanic forcings, the two dominant natural contributors of climate change since the pre-industrial time.

8.4.1 Solar Irradiance

In earlier IPCC reports the forcing was estimated as the instantaneous RF at TOA. However, due to wavelength-albedo dependence, solar radiation-wavelength dependence and absorption within the stratosphere and the resulting stratospheric adjustment, the RF is reduced to about 78% of the TOA instantaneous RF (Gray et al., 2009). There is *low confidence* in the exact value of this number, which can be model and time scale dependent (Gregory et al., 2004; Hansen et al., 2005). AR4 gives an 11-year running mean instantaneous TOA RF between 1750 and the present of 0.12 W m^{-2} with a range of estimates of 0.06 to 0.30 W m^{-2}, equivalent to a RF of 0.09 W m^{-2} with a range of 0.05 to 0.23 W m^{-2}. For a consistent treatment of all forcing agents, hereafter we use RF while numbers quoted from AR4 will be provided both as RF and instantaneous RF at TOA.

8.4.1.1 Satellite Measurements of Total Solar Irradiance

Total solar irradiance (TSI) measured by the Total Irradiance Monitor (TIM) on the spaceborne Solar Radiation and Climate Experiment (SORCE) is 1360.8 ± 0.5 W m^{-2} during 2008 (Kopp and Lean, 2011) which is ~4.5 W m^{-2} lower than the Physikalisch-Meteorologisches Observatorium Davos (PMOD) TSI composite during 2008 (Frohlich, 2009).The difference is probably due to instrumental biases in measurements prior to TIM. Measurements with the PREcision MOnitor Sensor (PREMOS) instrument support the TIM absolute values (Kopp and Lean, 2011). The TIM calibration is also better linked to national standards which provides further support that it is the most accurate (see Supplementary Material Section 8.SM.6). Given the lower TIM TSI values relative to currently used standards, most general circulation models are calibrated to incorrectly high values. However, the few tenths of a percent bias in the absolute TSI value has minimal consequences for climate simulations because the larger uncertainties in cloud properties have a greater effect on the radiative balance. As the maximum-to-minimum TSI relative change is well-constrained from observations, and historical variations are calculated as changes relative to modern values, a revision of the absolute value of TSI affects RF by the same fraction as it affects TSI. The downward revision of TIM TSI with respect to PMOD, being 0.3%, thus has a negligible impact on RF, which is given with a relative uncertainty of several tenths of a percent.

Since 1978, several independent space-based instruments have directly measured the TSI. Three main composite series were constructed, referred to as the Active Cavity Radiometer Irradiance Monitor (ACRIM) (Willson and Mordvinov, 2003), the Royal Meteorological Institute of Belgium (RMIB) (Dewitte et al., 2004) and the PMOD (Frohlich, 2006) series. There are two major differences between ACRIM and PMOD. The first is the rapid drift in calibration between PMOD and ACRIM before 1981. This arises because both composites employ the Hickey–Frieden (HF) radiometer data for this interval, while a re-evaluation of the early HF degradation has been implemented by PMOD but not by ACRIM. The second one, involving also RMIB, is the bridging of the gap between the end of ACRIM I (mid-1989) and the beginning of ACRIM II (late 1991) observations, as it is possible that a change in HF data occurred during this gap. This possibility is neglected in ACRIM and thus its TSI increases by more than 0.5 W m^{-2} during solar cycle (SC) 22. These differences lead to different long-term TSI trends in the three composites (see Figure 8.10): ACRIM rises until 1996 and subsequently declines, RMIB has an upward trend through 2008 and PMOD shows a decline since 1986 which unlike the other two composites, follows the solar-cycle-averaged sunspot number (Lockwood, 2010). Moreover, the ACRIM trend implies that the TSI on time scales longer than the SC is positively correlated with the cosmic ray variation indicating a decline in TSI throughout most of the 20th century (the opposite to most TSI reconstructions produced to date; see Section 8.4.1.2). Furthermore, extrapolating the ACRIM TSI long-term drift would imply a brighter Sun in the Maunder minimum (MM) than now, again opposite to most TSI reconstructions (Lockwood and Frohlich, 2008). Finally, analysis of instrument degradation and pointing issues (Lee et al., 1995) and independent modeling based on solar magnetograms (Wenzler et al.,

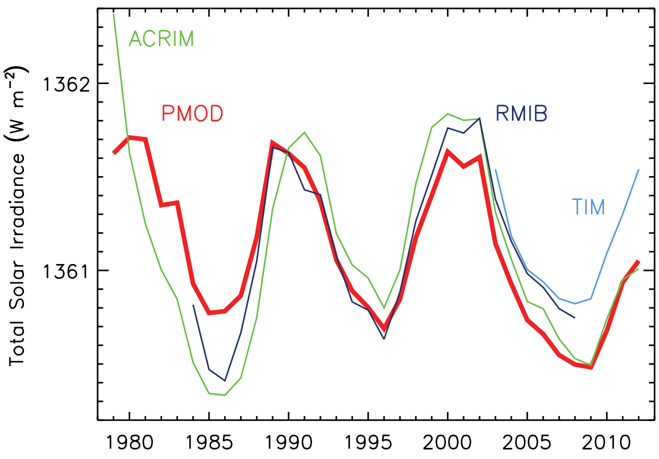


Figure 8.10 | Annual average composites of measured total solar irradiance: The Active Cavity Radiometer Irradiance Monitor (ACRIM) (Willson and Mordvinov, 2003), the Physikalisch-Meteorologisches Observatorium Davos (PMOD) (Frohlich, 2006) and the Royal Meteorological Institute of Belgium (RMIB) (Dewitte et al., 2004).These composites are standardized to the annual average (2003–2012) Total Irradiance Monitor (TIM) (Kopp and Lean, 2011) measurements that are also shown.

2009; Ball et al., 2012), confirm the need for correction of HF data, and we conclude that PMOD is more accurate than the other composites.

TSI variations of approximately 0.1% were observed between the maximum and minimum of the 11-year SC in the three composites mentioned above (Kopp and Lean, 2011). This variation is mainly due to an interplay between relatively dark sunspots, bright faculae and bright network elements (Foukal and Lean, 1988; see Section 5.2.1.2). A declining trend since 1986 in PMOD solar minima is evidenced in Figure 8.10. Considering the PMOD solar minima values of 1986 and 2008, the RF is –0.04 W m^{-2}. Our assessment of the uncertainty range of changes in TSI between 1986 and 2008 is –0.08 to 0.0 W m^{-2} and thus *very likely* negative, and includes the uncertainty in the PMOD data (Frohlich, 2009; see Supplementary Material Section 8.SM.6) but is extended to also take into account the uncertainty of combining the satellite data.

For incorporation of TIM data with the previous and overlapping data, in Figure 8.10 we have standardized the composite time series to the TIM series (over 2003–2012, the procedure is explained in Supplementary Material Section 8.SM.6. Moreover as we consider annual averages, ACRIM and PMOD start at 1979 because for 1978 both composites have only two months of data.

8.4.1.2 Total Solar Irradiance Variations Since Preindustrial Time

The year 1750, which is used as the preindustrial reference for estimating RF, corresponds to a maximum of the 11-year SC. Trend analysis are usually performed over the minima of the solar cycles that are more stable. For such trend estimates, it is then better to use the closest SC minimum, which is in 1745. To avoid trends caused by comparing different portions of the solar cycle, we analyze TSI changes using multi-year running means. For the best estimate we use a recent TSI reconstruction by Krivova et al. (2010) between 1745 and 1973 and from 1974 to 2012 by Ball et al. (2012). The reconstruction is based on physical modeling of the evolution of solar surface magnetic flux, and its relationship with sunspot group number (before 1974) and sunspot umbra and penumbra and faculae afterwards. This provides a more detailed reconstruction than other models (see the time series in Supplementary Material Table 8.SM.3). The best estimate from our assessment of the most reliable TSI reconstruction gives a 7-year running mean RF between the minima of 1745 and 2008 of 0.05 W m^{-2}. Our assessment of the range of RF from TSI changes is 0.0 to 0.10 W m^{-2} which covers several updated reconstructions using the same 7-year running mean past-to-present minima years (Wang et al., 2005; Steinhilber et al., 2009; Delaygue and Bard, 2011), see Supplementary Material Table 8.SM.4. All reconstructions rely on indirect proxies that inherently do not give consistent results. There are relatively large discrepancies among the models (see Figure 8.11).With these considerations, we adopt this value and range for AR5. This RF is almost half of that in AR4, in part because the AR4 estimate was based on the previous solar cycle minimum while the AR5 estimate includes the drop of TSI in 2008 compared to the previous two SC minima (see 8.4.1). Concerning the uncertainty range, in AR4 the upper limit corresponded to the reconstruction of Lean (2000), based on the reduced brightness of non-cycling Sun-like stars assumed typical of a Maunder minimum (MM) state. The use of such stellar analogues was based on the work of Baliunas and Jastrow (1990), but more recent surveys have not reproduced their results and suggest that the selection of the original set was flawed (Hall and Lockwood, 2004; Wright, 2004); the lower limit from 1750 to present in AR4 was due to the assumed increase in the amplitude of the 11-year cycle only. Thus the RF and uncertainty range have been obtained in a different way in AR5 compared to AR4. Maxima to maxima RF give a higher estimate than minima to minima RF, but the latter is more relevant for changes in solar activity. Given the *medium agreement* and *medium evidence*, this RF value has a *medium confidence level* (although confidence is higher for the last three decades). Figure 8.11 shows several TSI reconstructions modelled using sunspot group numbers (Wang et al., 2005; Krivova et al., 2010;

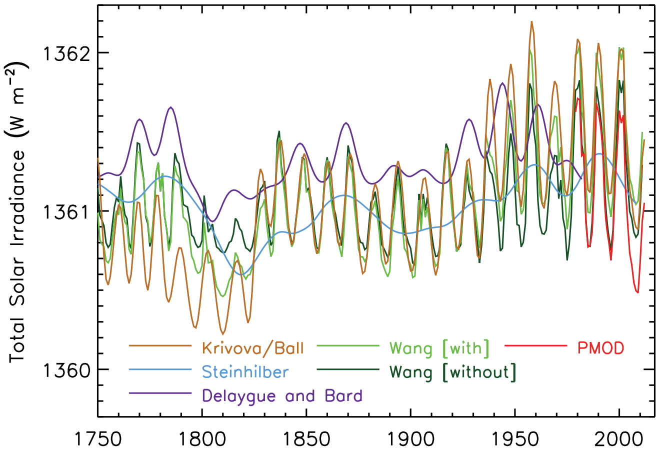


Figure 8.11 | Reconstructions of total solar irradiance since1745; annual resolution series from Wang et al. (2005) with and without an independent change in the background level of irradiance, Krivova et al. (2010) combined with Ball et al. (2012) and 5-year time resolution series from Steinhilber et al. (2009) and Delaygue and Bard (2011). The series are standardized to the Physikalisch-Meteorologisches Observatorium Davos (PMOD) measurements of solar cycle 23 (1996–2008) (PMOD is already standardized to Total Irradiance Monitor).

Ball et al., 2012) and sunspot umbra and penumbra and faculae (Ball et al., 2012), or cosmogenic isotopes (Steinhilber et al., 2009; Delaygue and Bard, 2011). These reconstructions are standardized to PMOD SC 23 (1996–2008) (see also Supplementary Material Section 8.SM.6).

For the MM-to-present AR4 gives a TOA instantaneous RF range of 0.1 to 0.28 W m^{-2}, equivalent to 0.08 to 0.22 W m^{-2} with the RF definition used here. The reconstructions in Schmidt et al. (2011) indicate a MM-to-present RF range of 0.08 to 0.18 W m^{-2}, which is within the AR4 range although narrower. As discussed above, the estimates based on irradiance changes in Sun-like stars are not included in this range because the methodology has been shown to be flawed. A more detailed explanation of this is found in Supplementary Material Section 8.SM.6. For details about TSI reconstructions on millennia time scales see Section 5.2.1.2.

8.4.1.3 Attempts to Estimate Future Centennial Trends of Total Solar Irradiance

Cosmogenic isotope and sunspot data (Rigozo et al., 2001; Solanki and Krivova, 2004; Abreu et al., 2008) reveal that currently the Sun is in a grand activity maximum that began about 1920 (20th century grand maximum). However, SC 23 showed an activity decline not previously seen in the satellite era (McComas et al., 2008; Smith and Balogh, 2008; Russell et al., 2010). Most current estimations suggest that the forthcoming solar cycles will have lower TSI than those for the past 30 years (Abreu et al., 2008; Lockwood et al., 2009; Rigozo et al., 2010; Russell et al., 2010). Also there are indications that the mean magnetic field in sunspots may be diminishing on decadal level. A linear expansion of the current trend may indicate that of the order of half the sunspot activity may disappear by about 2015 (Penn and Livingston, 2006). These studies only suggest that the Sun may have left the 20th century grand maximum and not that it is entering another grand minimum. But other works propose a grand minimum during the 21st century, estimating an RF within a range of -0.16 to 0.12 W m^{-2} between this future minimum and the present-day TSI (Jones et al., 2012). However, much more evidence is needed and at present there is *very low confidence* concerning future solar forcing estimates.

Nevertheless, even if there is such decrease in the solar activity, there is a *high confidence* that the TSI RF variations will be much smaller in magnitude than the projected increased forcing due to GHG (see Section 12.3.1).

8.4.1.4 Variations in Spectral Irradiance

8.4.1.4.1 Impacts of ultraviolet variations on the stratosphere

Ozone is the main gas involved in stratospheric radiative heating. Ozone production rate variations are largely due to solar UV irradiance changes (HAIGH, 1994), with observations showing statistically significant variations in the upper stratosphere of 2 to 4% along the SC (Soukharev and Hood, 2006). UV variations may also produce transport-induced ozone changes due to indirect effects on circulation (Shindell et al., 2006b). In addition, statistically significant evidence for an 11-year variation in stratospheric temperature and zonal winds is attributed to UV radiation (Frame and Gray, 2010). The direct UV heating of the background ozone is dominant and over twice as large as the ozone heating in the upper stratosphere and above, while indirect solar and terrestrial radiation through the SC-induced ozone change is dominant below about 5 hPa (Shibata and Kodera, 2005). The RF due to solar-induced ozone changes is a small fraction of the solar RF discussed in Section 8.4.1.1 (Gray et al., 2009).

8.4.1.4.2 Measurements of spectral irradiance

Solar spectral irradiance (SSI) variations in the far (120 to 200 nm) and middle (200 to 300 nm) ultraviolet (UV) are the primary driver for heating, composition, and dynamic changes of the stratosphere, and although these wavelengths compose a small portion of the incoming radiation they show large relative variations between the maximum and minimum of the SC compared to the corresponding TSI changes. As UV heating of the stratosphere over a SC has the potential to influence the troposphere indirectly, through dynamic coupling, and therefore climate (Haigh, 1996; Gray et al., 2010), the UV may have a more significant impact on climate than changes in TSI alone would suggest. Although this indicates that metrics based only on TSI are not appropriate, UV measurements present several controversial issues and modelling is not yet robust.

Multiple space-based measurements made in the past 30 years indicated that UV variations account for about 30% of the SC TSI variations, while about 70% were produced within the visible and infrared (Rottman, 2006). However, current models and data provide the range of 30 to 90% for the contribution of the UV variability below 400 nm to TSI changes (Ermolli et al., 2013), with a more probable value of ~60% (Morrill et al., 2011; Ermolli et al., 2013). The Spectral Irradiance Monitor (SIM) on board SORCE (Harder et al., 2009) shows, over the SC 23 declining phase, measurements that are rather inconsistent with prior understanding, indicating that additional validation and uncertainty estimates are needed (DeLand and Cebula, 2012; Lean and Deland, 2012). A wider exposition can be found in Supplementary Material Section 8.SM.6.

8.4.1.4.3 Reconstructions of preindustrial ultraviolet variations

The Krivova et al. (2010) reconstruction is based on what is known about spectral contrasts of different surface magnetic features and the relationship between TSI and magnetic fields. The authors interpolated backwards to the year 1610 based on sunspot group numbers and magnetic information. The Lean (2000) model is based on historical sunspot number and area and is scaled in the UV using measurements from the Solar Stellar Irradiance Comparison Experiment (SOLSTICE) on board the Upper Atmosphere Research Satellite (UARS). The results show smoothed 11-year UV SSI changes between 1750 and the present of about 25% at about 120 nm, about 8% at 130 to 175 nm, ~4% at 175 to 200 nm, and about 0.5% at 200 to 350 nm. Thus, the UV SSI appears to have generally increased over the past four centuries, with larger trends at shorter wavelengths. As few reconstructions are available, and recent measurements suggest a poor understanding of UV variations and their relationship with solar activity, there is *very low confidence* in these values.

8.4.1.5 The Effects of Cosmic Rays on Clouds

Changing cloud amount or properties modify the Earth's albedo and therefore affect climate. It has been hypothesized that cosmic ray flux create atmospheric ions which facilitates aerosol nucleation and new particle formation with a further impact on cloud formation (Dickinson, 1975; Kirkby, 2007). High solar activity means a stronger heliospheric magnetic field and thus a more efficient screen against cosmic rays. Under the hypothesis underlined above, the reduced cosmic ray flux would promote fewer clouds amplifying the warming effect expected from high solar activity. There is evidence from laboratory, field and modelling studies that ionization from cosmic ray flux may enhance aerosol nucleation in the free troposphere (Merikanto et al., 2009; Mirme et al., 2010; Kirkby et al., 2011). However, there is *high confidence* (*medium evidence* and *high agreement*) that the cosmic ray–ionization mechanism is too weak to influence global concentrations of cloud condensation nuclei or their change over the last century or during a SC in a climatically significant way (Harrison and Ambaum, 2010; Erlykin and Wolfendale, 2011; Snow-Kropla et al., 2011). A detailed exposition is found in Section 7.4.6.

8.4.2 Volcanic Radiative Forcing

8.4.2.1 Introduction

Volcanic eruptions that inject substantial amounts of SO_2 gas into the stratosphere are the dominant natural cause of externally forced climate change on the annual and multi-decadal time scales, both because of the multi-decadal variability of eruptions and the time scale of the climate system response, and can explain much of the pre-industrial climate change of the last millennium (Schneider et al., 2009; Brovkin et al., 2010; Legras et al., 2010; Miller et al., 2012). Although volcanic eruptions inject both mineral particles (called ash or tephra) and sulphate aerosol precursor gases (predominantly SO_2) into the atmosphere, it is the sulphate aerosols, which because of their small size are effective scatterers of sunlight and have long lifetimes, that are responsible for RF important for climate. Global annually averaged emissions of CO_2 from volcanic eruptions since 1750 have been at least 100 times smaller than anthropogenic emissions and inconsequential for climate on millennial and shorter time scales (Gerlach, 2011). To be important for climate change, sulphur must be injected into the stratosphere, as the lifetime of aerosols in the troposphere is only about one week, whereas sulphate aerosols in the stratosphere from tropical eruptions have a lifetime of about one year, and those from high-latitude eruptions last several months. Most stratospheric aerosols are from explosive eruptions that directly put sulphur into the stratosphere, but Bourassa et al. (2012, 2013) showed that sulphur injected into the upper troposphere can then be lifted into the stratosphere over the next month or two by deep convection and large scale Asian summer monsoon circulation, although Vernier et al. (2013) and Fromm et al. (2013) suggested that direct injection was also important. Robock (2000), AR4 (Forster et al., 2007) and Timmreck (2012) provide summaries of this relatively well understood forcing agent.

There have been no major volcanic eruptions since Mt Pinatubo in 1991 (Figure 8.12), but several smaller eruptions have caused a RF for the years 2008–2011 of –0.11 (–0.15 to –0.08) W m^{-2}, approximately twice the magnitude of the 1999–2002 RF of –0.06 (–0.08 to –0.04) W m^{-2}, consistent with the trends noted in Solomon et al. (2011). However, the CMIP5 simulations discussed elsewhere in this report did not include the recent small volcanic forcing in their calculations. New work has also produced a better understanding of high latitude eruptions, the hydrological response to volcanic eruptions (Trenberth and Dai, 2007; Anchukaitis et al., 2010), better long-term records of past volcanism and better understanding of the effects of very large eruptions.

There are several ways to measure both the SO_2 precursor and sulphate aerosols in the stratosphere, using balloons, airplanes, and both ground- and satellite-based remote sensing. Both the infrared and ultraviolet signals sensed by satellite instruments can measure SO_2, and stratospheric aerosol measurements by space-based sensors have been made on a continuous basis since 1978 by a number of instruments employing solar and stellar occultation, limb scattering, limb emission, and lidar strategies (Thomason and Peter, 2006; Kravitz et al., 2011; Solomon et al., 2011).

Forster et al. (2007) described four mechanisms by which volcanic forcing influences climate: RF due to aerosol–radiation interaction; differential (vertical or horizontal) heating, producing gradients and changes in circulation; interactions with other modes of circulation, such as El Niño-Southern Oscillation (ENSO); and ozone depletion with its effects on stratospheric heating, which depends on anthropogenic chlorine (stratospheric ozone would increase with a volcanic eruption under low-chlorine conditions). In addition, the enhanced diffuse light from volcanic aerosol clouds impacts vegetation and hence the carbon cycle (Mercado et al., 2009) and aerosol–cloud interaction of sulphate aerosols on clouds in the troposphere can also be important (Schmidt et al., 2010), though Frolicher et al. (2011) showed that the impacts of the 1991 Mt Pinatubo eruption on the carbon cycle were small.

8.4.2.2 Recent Eruptions

The background stratospheric aerosol concentration was affected by several small eruptions in the first decade of the 21st century (Nagai et al., 2010; Vernier et al., 2011; Neely et al., 2013; see also Figure 8.13), with a very small contribution from tropospheric pollution (Siddaway and Petelina, 2011; Vernier et al., 2011), and had a small impact on RF (Solomon et al., 2011). Two recent high-latitude eruptions, of Kasatochi Volcano (52.1°N, 175.3°W) on August 8, 2008 and of Sarychev Volcano (48.1°N, 153.2°E) on June 12–16, 2009, each injected ~1.5 Tg(SO_2) into the stratosphere, but did not produce detectable climate response. Their eruptions, however, led to better understanding of the dependence of the amount of material and time of year of high-latitude injections to produce climate impacts (Haywood et al., 2010; Kravitz et al., 2010, 2011). The RF from high-latitude eruptions is a function of seasonal distribution of insolation and the 3- to 4-month lifetime of high-latitude volcanic aerosols. Kravitz and Robock (2011) showed that high-latitude eruptions must inject at least 5 Tg(SO_2) into the lower stratosphere in the spring or summer, and much more in fall or winter, to have a detectible climatic response.

On April 14, 2010 the Eyjafjallajökull volcano in Iceland (63.6°N, 19.6°W) began an explosive eruption phase that shut down air traffic in Europe for 6 days and continued to disrupt it for another month. The climatic impact of Eyjafjallajökull was about 10,000 times less than that of Mt Pinatubo; however, because it emitted less than 50 ktonnes SO_2 and its lifetime in the troposphere was 50 times less than if it had been injected into the stratosphere, and was therefore undetectable amidst the chaotic weather noise in the atmosphere (Robock, 2010). 2011 saw the continuation of a number of small eruptions with significant tropospheric SO_2 and ash injections, including Puyehue-Cordón Caulle in Chile, Nabro in Eritrea, and Grimsvötn in Iceland. None have been shown to have produced an important RF, but the June 13, 2011 Nabro eruption resulted in the largest stratospheric aerosol cloud since the 1991 Mt Pinatubo eruption (Bourassa et al., 2012), more than 1.5 $Tg(SO_2)$.

Figure 8.12 shows reconstructions of volcanic aerosol optical depth since 1750. Figure 8.13 shows details of the vertical distribution of stratospheric aerosols in the tropics since 1985. The numerous small eruptions in the past decade are evident, but some of them were at higher latitudes and their full extent is not captured in this plot.

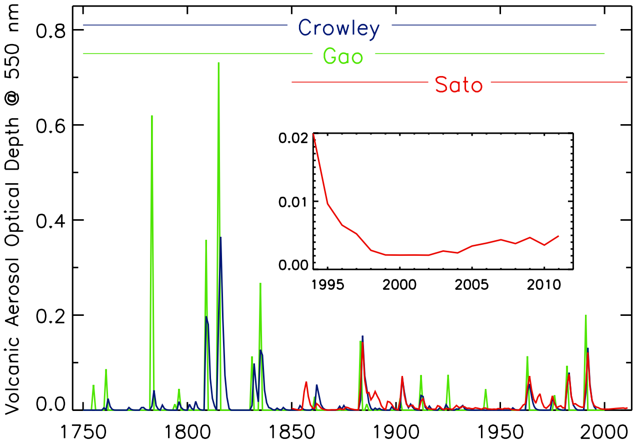


Figure 8.12 | Volcanic reconstructions of global mean aerosol optical depth (at 550 nm). Gao et al. (2008) and Crowley and Unterman (2013) are from ice core data, and end in 2000 for Gao et al. (2008) and 1996 for Crowley and Unterman (2013). Sato et al. (1993) includes data from surface and satellite observations, and has been updated through 2011. (Updated from Schmidt et al., 2011.)

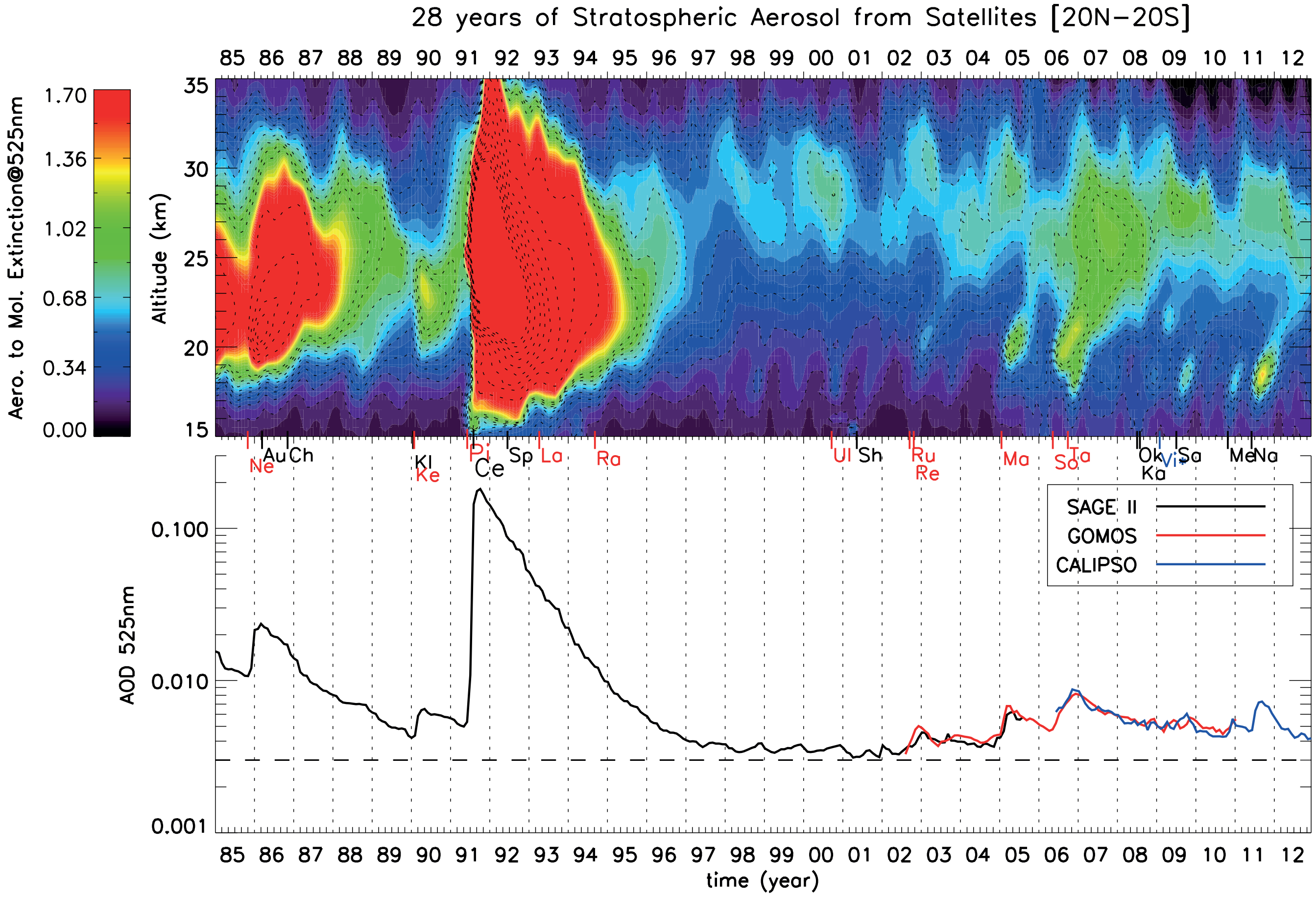


Figure 8.13 | (Top) Monthly mean extinction ratio (525 nm) profile evolution in the tropics [20°N to 20°S] from January 1985 through December 2012 derived from Stratospheric Aerosol and Gas Experiment (SAGE) II extinction in 1985–2005 and Cloud-Aerosol Lidar and Infrared Pathfinder Satellite Observation (CALIPSO) scattering ratio in 2006–2012, after removing clouds below 18 km based on their wavelength dependence (SAGE II) and depolarization properties (CALIPSO) compared to aerosols. Black contours represent the extinction ratio in log-scale from 0.1 to 100. The position of each volcanic eruption occurring during the period is displayed with its first two letters on the horizontal axis, where tropical eruptions are noted in red. The eruptions were Nevado del Ruiz (Ne), Augustine (Au), Chikurachki (Ch), Kliuchevskoi (Kl), Kelut (Ke), Pinatubo (Pi), Cerro Hudson (Ce), Spur (Sp), Lascar (La), Rabaul (Ra), Ulawun (Ul), Shiveluch (Sh), Ruang (Ru), Reventador (Re), Manam (Ma), Soufrière Hills (So), Tavurvur (Ta), Okmok (Ok), Kasatochi (Ka), Victoria (Vi*—forest fires with stratospheric aerosol injection), Sarychev (Sa), Merapi (Me), Nabro (Na). (Updated from Figure 1 from Vernier et al., 2011.) (Bottom) Mean stratospheric aerosol optical depth (AOD) in the tropics [20°N to 20°S] between the tropopause and 40 km since 1985 from the SAGE II (black line), the Global Ozone Monitoring by Occultation of Stars (GOMOS) (red line), and CALIPSO (blue line). (Updated from Figure 5 from Vernier et al., 2011.)

Box 8.3 | Volcanic Eruptions as Analogues

Volcanic eruptions provide a natural experiment of a stratospheric aerosol cloud that can serve to inform us of the impacts of the proposed production of such a cloud as a means to control the climate, which is one method of geoengineering (Rasch et al., 2008); see Section 7.7. For example, Trenberth and Dai (2007) showed that the Asian and African summer monsoon, as well as the global hydrological cycle, was weaker for the year following the 1991 Mt Pinatubo eruption, which is consistent with climate model simulations (Robock et al., 2008). MacMynowski et al. (2011) showed that because the climate system response of the hydrological cycle is rapid, forcing from volcanic eruptions, which typically last about a year, can serve as good analogues for longer-lived forcing. The formation of sulphate aerosols, their transport and removal, their impacts on ozone chemistry, their RF, and the impacts on whitening skies all also serve as good analogues for geoengineering proposals. Volcanic impacts on the carbon cycle because of more diffuse radiation (Mercado et al., 2009) and on remote sensing can also be useful analogues, and the impacts of contrail-generated sub-visual cirrus (Long et al., 2009) can be used to test the long-term impacts of a permanent stratospheric cloud.

Smoke from fires generated by nuclear explosions on cities and industrial areas, which could be lofted into the stratosphere, would cause surface cooling and a reduction of stratospheric ozone (Mills et al., 2008). Volcanic eruptions that produce substantial stratospheric aerosol clouds also serve as an analogue that supports climate model simulations of the transport and removal of stratospheric aerosols, their impacts on ozone chemistry, their RF, and the climate response. The use of the current global nuclear arsenal still has the potential to produce nuclear winter, with continental temperatures below freezing in summer (Robock et al., 2007a; Toon et al., 2008), and the use of only 100 nuclear weapons could produce climate change unprecedented in recorded human history (Robock et al., 2007b), with significant impacts on global agriculture (Özdoğan et al., 2013; Xia and Robock, 2013).

8.4.2.3 Records of Past Volcanism and Effects of Very Large Eruptions

Although the effects of volcanic eruptions on climate are largest in the 2 years following a large stratospheric injection, and the winter warming effect in the NH has been supported by long-term records (Fischer et al., 2007), there is new work indicating extended volcanic impacts via long-term memory in the ocean heat content and sea level (Stenchikov et al., 2009; Gregory, 2010; Otterä et al., 2010). Zanchettin et al. (2012) found changes in the North Atlantic Ocean circulation that imply strengthened northward oceanic heat transport a decade after major eruptions, which contributes to the emergence of extensive winter warming over the continental NH along with persistent cooling over Arctic regions on decadal time scales, in agreement with Zhong et al. (2011) and Miller et al. (2012).

New work on the mechanisms by which a supereruption (Self and Blake, 2008) could force climate has focused on the 74,000 BP eruption of the Toba volcano (2.5°N, 99.0°E). Robock et al. (2009) used simulations of up to 900 times the 1991 Mt Pinatubo sulphate injection to show that the forcing is weaker than that predicted based on a linear relationship with the sulphate aerosol injection. The results agreed with a previous simulation by Jones et al. (2005). They also showed that chemical interactions with ozone had small impacts on the forcing and that the idea of Bekki et al. (1996) that water vapour would limit and prolong the growth of aerosols was not supported. Timmreck et al. (2010) however, incorporating the idea of Pinto et al. (1989) that aerosols would grow and therefore both have less RF per unit mass and fall out of the atmosphere more quickly, found much less of a radiative impact from such a large stratospheric input.

8.4.2.4 Future Effects

We expect large eruptions over the next century but cannot predict when. Ammann and Naveau (2003) and Stothers (2007) suggested an 80-year periodicity in past eruptions, but the data record is quite short and imperfect, and there is no mechanism proposed that would cause this. While the period 1912–1963 was unusual for the past 500 years in having no large volcanic eruptions, and the period 1250–1300 had the most globally climatically significant eruptions in the past 1500 years (Gao et al., 2008), current knowledge only allows us to predict such periods on a statistical basis, assuming that the recent past distributions are stationary. Ammann and Naveau (2003), Gusev (2008), and Deligne et al. (2010) studied these statistical properties and Ammann and Naveau (2010) showed how they could be used to produce a statistical distribution for future simulations. Although the future forcing from volcanic eruptions will depend only on the stratospheric aerosol loading for most forcing mechanisms, the future effects on reducing ozone will diminish as ozone depleting substances diminish in the future (Eyring et al., 2010b).

8.5 Synthesis of Global Mean Radiative Forcing, Past and Future

The RF can be used to quantify the various agents that drive climate change over the Industrial Era or the various contributions to future climate change. There are multiple ways in which RF can be attributed to underlying causes, each providing various perspectives on the importance of the different factors driving climate change. This section evaluates the RF with respect to emitted component and with respect to the ultimate atmospheric concentrations. The uncertainties in the RF agents vary and the confidence levels for these are presented in this section. Finally, this section shows historical and scenarios of future time evolution of RF.

8.5.1 Summary of Radiative Forcing by Species and Uncertainties

Table 8.5 has an overview of the RF agents considered here and each of them is given a confidence level for the change in RF over the Industrial Era to the present day. The confidence level is based on the evidence (robust, medium, and limited) and the agreement (high, medium, and low; see further description in Chapter 1). The confidence level of the forcing agents goes beyond the numerical values available in estimates and is an assessment for a particular forcing agent to have a real value within the estimated range. Some of the RF agents have robust evidence such as WMGHG with well documented increases based on high precision measurements as well as contrails as additional clouds which can be seen by direct observations. However, for some forcing agents the evidence is more limited regarding their existence such as aerosol influence on cloud cover. The consistency in the findings for a particular forcing agent determines the evaluation of the evidence. A combination of different methods, for example, observations and modeling, and thus the understanding of the processes causing the forcing is important for this evaluation. The agreement is a qualitative judgment of the difference between the various estimates for a particular RF agent. Figure 1.11 shows how the combined evidence and agreement results in five levels for the confidence level.

Table 8.5 | Confidence level for the forcing estimate associated with each forcing agent for the 1750–2011 period. The confidence level is based on the evidence and the agreement as given in the table. The basis for the confidence level and change since AR4 is provided. See Figure 1.11 for further description of the evidence, agreement and confidence level. The colours are adopted based on the evidence and agreement shown in Figure 1.11. Dark green is "High agreement and Robust evidence", light green is either "High agreement and Medium evidence" or "Medium agreement and Robust evidence", yellow is either "High agreement and limited evidence" or "Medium agreement and Medium evidence" or "Low agreement and Robust evidence", orange is either "Medium agreement and Limited evidence" or "Low agreement and Medium evidence" and finally red is "Low agreement and Limited evidence". Note, that the confidence levels given in Table 8.5 are for 2011 relative to 1750 and for some of the agents the confidence level may be different for certain portions of the Industrial Era.

	Evidence	Agreement	Confidence Level	Basis for Uncertainty Estimates (more certain / less certain)	Change in Understanding Since AR4
Well-mixed greenhouse gases	Robust	High	*Very high*	Measured trends from different observed data sets and differences between radiative transfer models	No major change
Tropospheric ozone	Robust	Medium	*High*	Observed trends of ozone in the troposphere and model results for the industrial era/Differences between model estimates of RF	No major change
Stratospheric ozone	Robust	Medium	*High*	Observed trends in stratospheric and total ozone and modelling of ozone depletion/Differences between estimates of RF	No major change
Stratospheric water vapour from CH_4	Robust	Low	*Medium*	Similarities in results of independent methods to estimate the RF/Known uncertainty in RF calculations	Elevated owing to more studies
Aerosol–radiation interactions	Robust	Medium	*High*	A large set of observations and converging independent estimates of RF/Differences between model estimates of RF	Elevated owing to more robust estimates from independent methods
Aerosol–cloud interactions	Medium	Low	*Low*	Variety of different observational evidence and modelling activities/Spread in model estimates of ERF and differences between observations and model results	ERF in AR5 has a similar confidence level to RF in AR4
Rapid adjustment aerosol–radiation interactions	Medium	Low	*Low*	Observational evidence combined with results from different types of models/Large spread in model estimates	Elevated owing to increased evidence
Total aerosol effect	Medium	Medium	*Medium*	A large set of observations and model results, independent methods to derive ERF estimates/Aerosol–cloud interaction processes and anthropogenic fraction of CCN still fairly uncertain	Not provided previously
Surface albedo (land use)	Robust	Medium	*High*	Estimates of deforestation for agricultural purposes and well known physical processes/Spread in model estimates of RF	Elevated owing to the availability of high-quality satellite data
Surface albedo (BC aerosol on snow and ice)	Medium	Low	*Low*	Observations of snow samples and the link between BC content in snow and albedo/Large spread in model estimates of RF	No major change
Contrails	Robust	Low	*Medium*	Contrails observations , large number of model estimates/Spread in model estimates of RF and uncertainties in contrail optical properties	Elevated owing to more studies
Contrail- induced cirrus	Medium	Low	*Low*	Observations of a few events of contrail induced cirrus/Extent of events uncertain and large spread in estimates of ERF	Elevated owing to additional studies increasing the evidence
Solar irradiance	Medium	Medium	*Medium*	Satellite information over recent decades and small uncertainty in radiative transfer calculations/Large relative spread in reconstructions based on proxy data	Elevated owing to better agreement of a weak RF
Volcanic aerosol	Robust	Medium	*High*	Observations of recent volcanic eruptions/Reconstructions of past eruptions	Elevated owing to improved understanding

Notes:

The confidence level for aerosol–cloud interactions includes rapid adjustments (which include what was previously denoted as cloud lifetime effect or second indirect aerosol effect). The separate confidence level for the rapid adjustment for aerosol–cloud interactions is very low. For aerosol–radiation interaction the table provides separate confidence levels for RF due to aerosol–radiation interaction and rapid adjustment associated with aerosol–radiation interaction.

Evidence is robust for several of the RF agents because of long term observations of trends over the industrial era and well defined links between atmospheric or land surfaced changes and their radiative effects. Evidence is medium for a few agents where the anthropogenic changes or the link between the forcing agent and its radiative effect are less certain. Medium evidence can be assigned in cases where observations or modelling provide a diversity of information and thus not a consistent picture for a given forcing agent. We assess the evidence to be limited only for rapid adjusment associated with aerosol–cloud interaction where model studies in some cases indicate changes but direct observations of cloud alterations are scarce. High agreement is given only for the WMGHG where the relative uncertainties in the RF estimates are much smaller than for the other RF agents. Low agreement can either be due to large diversity in estimates of the magnitude of the forcing or from the fact that the method to estimate the forcing has a large uncertainty. Stratospheric water vapour is an example of the latter with modest difference in the few available estimates but a known large uncertainty in the radiative transfer calculations (see further description in Section 8.3.1).

Figure 8.14 shows the development of the confidence level over the last four IPCC assessments for the various RF mechanisms. In the previous IPCC reports level of scientific understanding (LOSU) has been used instead of confidence level. For comparison with previous IPCC assessments the LOSU is converted approximately to confidence level. Note that LOSU and confidence level use different terms for their rankings. The figure shows generally increasing confidence levels but also that more RF mechanisms have been included over time. The confidence levels for the RF due to aerosol–radiation interactions, surface albedo due to land use and volcanic aerosols have been raised and are now at the same ranking as those for change in stratospheric and tropospheric ozone. This is due to an increased understanding of key parameteres and their uncertainties for the elevated RF agents. For tropospheric and stratospheric ozone changes, research has shown further complexities with changes primarily influencing the troposphere or the stratosphere being linked to some extent (see Section 8.3.3). The rapid adjustment associated with aerosol–cloud interactions is given the *confidence* level *very low* and had a similar level in AR4. For rapid adjustment associated with aerosol–radiation interactions (previously denoted as semi-direct effect) the *confidence* level is *low* and is raised compared to AR4, as the evidence is improved and is now *medium* (see Section 7.5.2).

Table 8.6 shows the best estimate of the RF and ERF (for AR5 only) for the various RF agents from the various IPCC assessments. The RF due to WMGHG has increased by 16% and 8% since TAR and AR4,

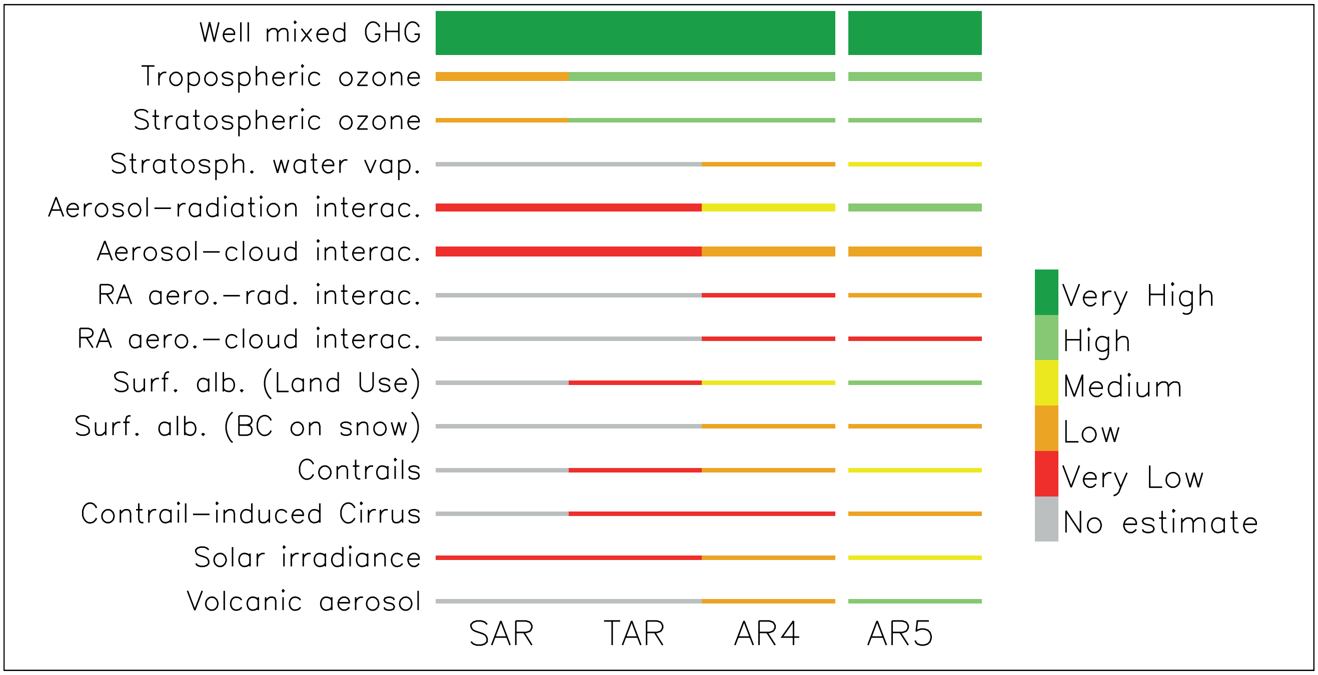


Figure 8.14 | Confidence level of the forcing mechanisms in the 4 last IPCC assessments. In the previous IPCC assessments the level of scientific understanding (LOSU) has been adopted instead of confidence level, but for comparison with previous IPCC assessments the LOSU is converted approximately to confidence level. The thickness of the bars represents the relative magnitude of the current forcing (with a minimum value for clarity of presentation). LOSU for the RF mechanisms was not available in the first IPCC Assessment (Houghton et al., 1990). Rapid adjustments associated with aerosol–cloud interactions (shown as RA aero. –cloud interac.) which include what was previously referred to as the second indirect aerosol effect or cloud lifetime effect whereas rapid adjustments associated with aerosol–radiation interactions (shown as RA aero.-rad. interac.) were previously referred to as the semi-direct effect (see Figure 7.3). In AR4 the confidence level for aerosol–cloud interaction was given both for RF due to aerosol–cloud interaction and rapid adjustment associated with aerosol–cloud interaction. Generally the aerosol–cloud interaction is not separated into various components in AR5, hence the confidence levels for ERF due to aerosol–cloud interaction in AR5 and for RF due to aerosol–cloud interaction from previous IPCC reports are compared. The confidence level for the rapid adjustment associated with aerosol–cloud interaction is comparable for AR4 and AR5. The colours are adopted based on the evidence and agreement shown in Figure 1.11. Dark green is "High agreement and Robust evidence", light green is either "High agreement and Medium evidence" or "Medium agreement and Robust evidence", yellow is either "High agreement and limited evidence" or "Medium agreement and Medium evidence" or "Low agreement and Robust evidence", orange is either "Medium agreement and Limited evidence" or "Low agreement and Medium evidence" and finally red is "Low agreement and Limited evidence".

respectively. This is due mainly to increased concentrations (see Section 8.3.2), whereas the other changes for the anthropogenic RF agents compared to AR4 are due to re-evaluations and in some cases from improved understanding. An increased number of studies, additional observational data and better agreement between models and observations can be the causes for such re-evaluations. The best estimates for RF due to aerosol–radiation interactions, BC on snow and solar irradiance are all substantially decreased in magnitude compared to AR4; otherwise the modifications to the best estimates are rather small. For the RF due to aerosol–radiation interaction and BC on snow the changes in the estimates are based on additional new studies since AR4 (see Section 8.3.4 and Section 7.5). For the change in the estimate of the solar irradiance it is a combination on how the RF is calculated, new evidence showing some larger earlier estimates were incorrect, and a downward trend observed during recent years in the solar activity that has been taken into account (see Section 8.4.1). The estimate for ERF due to to aerosol–cloud interaction includes rapid adjustment but still this ERF is smaller in magnitude than the AR4 RF estimate due to aerosol–cloud interactions without rapid adjustments (a theoretical construct not quantified in AR5). The uncertainties for ERF due to CO_2 increase when compared to RF (see Section 8.3.2). We assume the relative ERF uncertainties for CO_2 apply to all WMGHG. For the short-lived GHG we do not have sufficient information to include separate ERF uncertainty to each of these forcing agents (see Section 8.1.1.3). However, for these forcing mechanisms the RF uncertainties are larger than for the WMGHG and thus it is *unlikely* that rapid adjustments change the uncertainties substantially.

Figure 8.15 shows the RF for agents listed in Table 8.6 over the 1750–2011 period. The methods for calculation of forcing estimates are described in Section 8.3 and 8.4. For some of the components the forcing estimates are based on observed abundance whereas some are estimated from a combination of model simulations and observations and for others are purely model based. Solid bars are given for ERF, whereas RF values are given as (additional) hatched bars. Similarly the uncertainties are given for ERF in solid lines and dotted lines for RF. An important assumption is that different forcing mechanisms can be treated additively to calculate the total forcing (see Boucher and Haywood, 2001; Forster et al., 2007; Haywood and Schulz, 2007). Total ERF over the Industrial Era calculated from Monte Carlo simulations are shown in Figure 8.16, with a best estimate of 2.29 W m^{-2}. For each of the forcing agents a probability density function (PDF) is generated based on uncertainties provided in Table 8.6. The combination of the individual RF agents to derive total forcing follows the same approach as in AR4 (Forster et al., 2007) which is based on the method in Boucher and Haywood (2001). The PDF of the GHGs (sum of WMGHG, ozone and stratospheric water vapour) has a more narrow shape than the PDF for the aerosols owing to the much lower relative uncertainty.

Table 8.6 | Summary table of RF estimates for AR5 and comparison with the three previous IPCC assessment reports. ERF values for AR5 are included. For AR5 the values are given for the period 1750–2011, whereas earlier final years have been adopted in the previous IPCC assessment reports.

	Global Mean Radiative Forcing (W m^{-2})					ERF (W m^{-2})
	SAR (1750–1993)	TAR (1750–1998)	AR4 (1750–2005)	AR5 (1750–2011)	Comment	AR5
Well-mixed greenhouse gases (CO_2, CH_4, N_2O, and halocarbons)	2.45 (2.08 to 2.82)	2.43 (2.19 to 2.67)	2.63 (2.37 to 2.89)	2.83 (2.54 to 3.12)	Change due to increase in concentrations	2.83 (2.26 to 3.40)
Tropospheric ozone	+0.40 (0.20 to 0.60)	+0.35 (0.20 to 0.50)	+0.35 (0.25 to 0.65)	+0.40 (0.20 to 0.60)	Slightly modified estimate	
Stratospheric ozone	–0.1 (–0.2 to –0.05)	–0.15 (–0.25 to –0.05)	–0.05 (–0.15 to +0.05)	–0.05 (–0.15 to +0.05)	Estimate unchanged	
Stratospheric water vapour from CH_4	Not estimated	+0.01 to +0.03	+0.07 (+0.02, +0.12)	+0.07 (+0.02 to +0.12)	Estimate unchanged	
Aerosol–radiation interactions	Not estimated	Not estimated	–0.50 (–0.90 to –0.10)	–0.35 (–0.85 to +0.15)	Re-evaluated to be smaller in magnitude	–0.45 (–0.95 to +0.05)
Aerosol–cloud interactions	0 to –1.5 (sulphate only)	0 to –2.0 (all aerosols)	–0.70 (–1.80 to –0.30) (all aerosols)	Not estimated	Replaced by ERF and re-evaluated to be smaller in magnitude	–0.45 (–1.2 to 0.0)
Surface albedo (land use)	Not estimated	–0.20 (–0.40 to 0.0)	–0.20 (–0.40 to 0.0)	–0.15 (–0.25 to –0.05)	Re-evaluated to be slightly smaller in magnitude	
Surface albedo (black carbon aerosol on snow and ice)	Not estimated	Not estimated	+0.10 (0.0 to +0.20)	+0.04 (+0.02 to +0.09)	Re-evaluated to be weaker	
Contrails	Not estimated	+0.02 (+0.006 to +0.07)	+0.01 (+0.003 to +0.03)	+0.01 (+0.005 to +0.03)	No major change	
Combined contrails and contrail-induced cirrus	Not estimated	0 to +0.04	Not estimated	Not estimated		0.05 (0.02 to 0.15)
Total anthropogenic	Not estimated	Not estimated	1.6 (0.6 to 2.4)	Not estimated	Stronger positive due to changes in various forcing agents	2.3 (1.1 to 3.3)
Solar irradiance	+0.30 (+0.10 to +0.50)	+0.30 (+0.10 to +0.50)	+0.12 (+0.06 to +0.30)	+0.05 (0.0 to +0.10)	Re-evaluated to be weaker	

Notes:

Volcanic RF is not added to the table due to the periodic nature of volcanic eruptions, which makes it difficult to compare to the other forcing mechanisms.

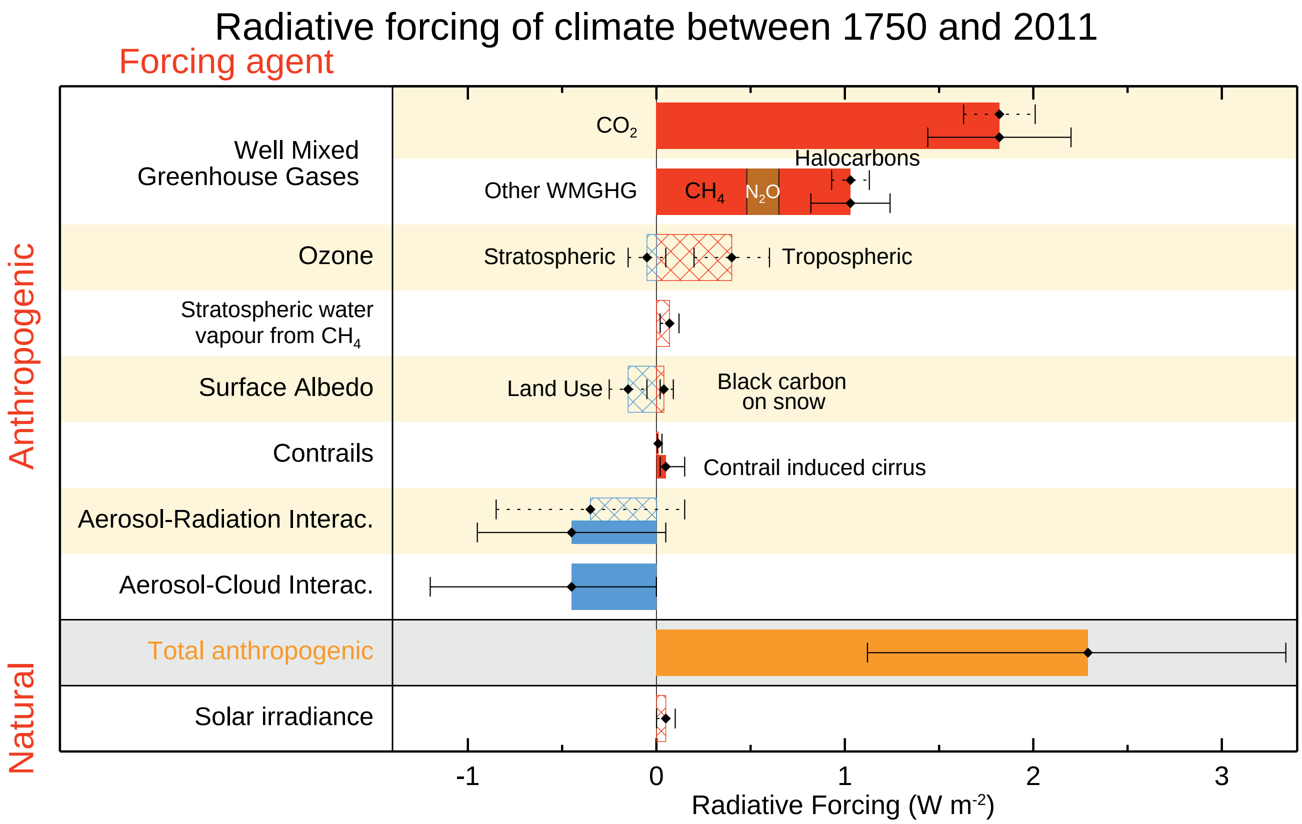


Figure 8.15 | Bar chart for RF (hatched) and ERF (solid) for the period 1750–2011, where the total ERF is derived from Figure 8.16. Uncertainties (5 to 95% confidence range) are given for RF (dotted lines) and ERF (solid lines).

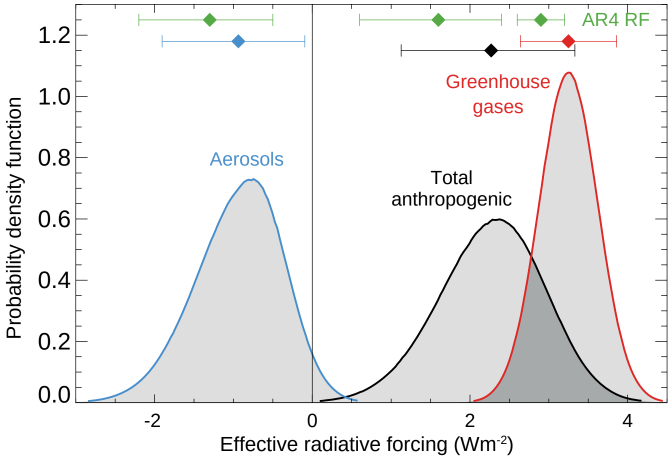


Figure 8.16 | Probability density function (PDF) of ERF due to total GHG, aerosol forcing and total anthropogenic forcing. The GHG consists of WMGHG, ozone and stratospheric water vapour. The PDFs are generated based on uncertainties provided in Table 8.6. The combination of the individual RF agents to derive total forcing over the Industrial Era are done by Monte Carlo simulations and based on the method in Boucher and Haywood (2001). PDF of the ERF from surface albedo changes and combined contrails and contrail-induced cirrus are included in the total anthropogenic forcing, but not shown as a separate PDF. We currently do not have ERF estimates for some forcing mechanisms: ozone, land use, solar, etc. For these forcings we assume that the RF is representative of the ERF and for the ERF uncertainty an additional uncertainty of 17% has been included in quadrature to the RF uncertainty. See Supplementary Material Section 8.SM.7 and Table 8.SM.4 for further description on method and values used in the calculations. Lines at the top of the figure compare the best estimates and uncertainty ranges (5 to 95% confidence range) with RF estimates from AR4.

Therefore, the large uncertainty in the aerosol forcing is the main cause of the large uncertainty in the total anthropogenic ERF. The total anthropogenic forcing is *virtually certain* to be positive with the probability for a negative value less than 0.1%. Compared to AR4 the total anthropogenic ERF is more strongly positive with an increase of 43%. This is caused by a combination of growth in GHG concentration, and thus strengthening in forcing of WMGHG, and weaker ERF estimates of aerosols (aerosol–radiation and aerosol–cloud interactions) as a result of new assessments of these effects.

Figure 8.17 shows the forcing over the Industrial Era by emitted compounds (see Supplementary Material Tables 8.SM.6 and 8.SM.7 for actual numbers and references). It is more complex to view the RF by emitted species than by change in atmospheric abundance (Figure 8.15) since the number of emitted compounds and changes leading to RF is larger than the number of compounds causing RF directly (see Section 8.3.3). The main reason for this is the indirect effect of several compounds and in particular components involved in atmospheric chemistry (see Section 8.2). To estimate the RF by the emitted compounds in some cases the emission over the entire Industrial Era is needed (e.g., for CO_2) whereas for other compounds (such as ozone and CH_4) quite complex simulations are required (see Section 8.3.3). CO_2 is the dominant positive forcing both by abundance and by emitted compound. Emissions of CH_4, CO, and NMVOC all lead to excess CO_2 as one end product if the carbon is of fossil origin and is the reason why the RF of direct CO_2 emissions is slightly lower than the RF of abundance change of CO_2. For CH_4 the contribution from emission is estimated to be almost twice as large as that from the CH_4 concentration change, 0.97 (0.80 to 1.14) W m^{-2} versus 0.48 (0.43 to 0.53) W m^{-2}, respectively. This is because emission of CH_4 leads to ozone production, stratospheric water vapour, CO_2 (as mentioned above), and importantly affects its own lifetime (Section 8.2). Actually, emissions of CH_4 would lead to a stronger RF via the direct CH_4 greenhouse effect (0.64 W m^{-2}) than the RF from abundance change of CH_4 (0.48 W m^{-2}). This is because other compounds have influenced the lifetime of CH_4 and reduced the abundance of CH_4, most notably NO_x. Emissions of CO (0.23 (0.18 to 0.29) W m^{-2}) and NMVOC (0.10 (0.06 to 0.14) W m^{-2}) have only indirect effects on RF through ozone production, CH_4 and CO_2 and thus contribute an overall positive RF. Emissions of NO_X, on the other hand, have indirect effects that lead to positive RF through ozone production and also effects that lead to negative RF through reduction of CH_4 lifetime and thus its concentration, and through contributions to nitrate aerosol formation. The best estimate of the overall effect of anthropogenic emissions of NO_X is a negative RF (-0.15 (-0.34 to +0.02) W m^{-2}). Emissions of ammonia also contribute to nitrate aerosol formation, with a small offset due to compensating changes in sulphate aerosols. Additionally indirect effects from sulphate on atmospheric compounds are not included here as models typically simulate a small effect, but there are large relative differences in the response between models. Impacts of emissions other than CO_2 on the carbon cycle via changes in atmospheric composition (ozone or aerosols) are also not shown owing to the limited amount of available information.

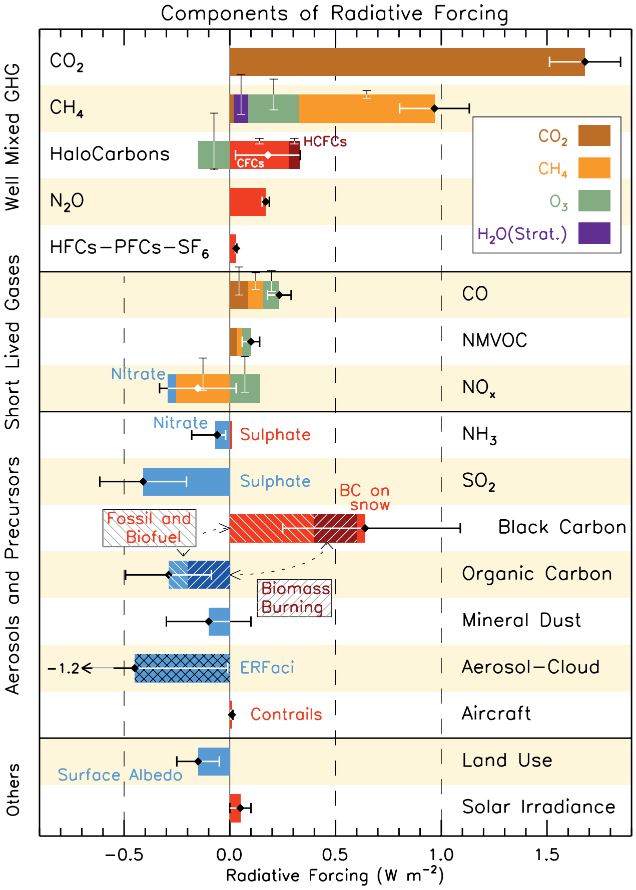


Figure 8.17 | RF bar chart for the period 1750–2011 based on emitted compounds (gases, aerosols or aerosol precursors) or other changes. Numerical values and their uncertainties are shown in Supplementary Material Tables 8.SM.6 and 8.SM.7. Note that a certain part of CH_4 attribution is not straightforward and discussed further in Section 8.3.3. Red (positive RF) and blue (negative forcing) are used for emitted components which affect few forcing agents, whereas for emitted components affecting many compounds several colours are used as indicated in the inset at the upper part the figure. The vertical bars indicate the relative uncertainty of the RF induced by each component. Their length is proportional to the thickness of the bar, that is, the full length is equal to the bar thickness for a ±50% uncertainty. The net impact of the individual contributions is shown by a diamond symbol and its uncertainty (5 to 95% confidence range) is given by the horizontal error bar. ERFaci is ERF due to aerosol–cloud interaction. BC and OC are co-emitted, especially for biomass burning emissions (given as Biomass Burning in the figure) and to a large extent also for fossil and biofuel emissions (given as Fossil and Biofuel in the figure where biofuel refers to solid biomass fuels). SOA have not been included because the formation depends on a variety of factors not currently sufficiently quantified.

For the WMGHG, the ERF best estimate is the same as the RF. The uncertainty range is slightly larger, however. The total emission-based ERF of WMGHG is 3.00 (2.22 to 3.78) W m^{-2}. That of CO_2 is 1.68 (1.33 to 2.03) W m^{-2}; that of CH_4 is 0.97 (0.74 to 1.20) W m^{-2}; that of stratospheric ozone-depleting halocarbons is 0.18 (0.01 to 0.35) W m^{-2}.

Emissions of BC have a positive RF through aerosol–radiation interactions and BC on snow (0.64 W m^{-2}, see Section 8.3.4 and Section 7.5). The emissions from the various compounds are co-emitted; this is in particular the case for BC and OC from biomass burning aerosols. The net RF of biomass burning emissions for aerosol–radiation interactions is close to zero, but with rather strong positive RF from BC and negative RF from OC (see Sections 8.3.4 and 7.5). The ERF due to aerosol–cloud interactions is caused by primary anthropogenic emissions of BC, OC and dust as well as secondary aerosol from anthropogenic emissions of SO_2, NO_X and NH_3. However, quantification of the contribution from the various components to the ERF due to aerosol–cloud interactions has not been attempted in this assessment.

8.5.2 Time Evolution of Historical Forcing

The time evolution of global mean forcing is shown in Figure 8.18 for the Industrial Era. Over all time periods during the Industrial Era CO_2 and other WMGHG have been the dominant term, except for shorter periods with strong volcanic eruptions. The time evolution shows an almost continuous increase in the magnitude of anthropogenic ERF. This is the case both for CO_2 and other WMGHGs as well as several individual aerosol components. The forcing from CO_2 and other WMGHGs has increased somewhat faster since the 1960s. Emissions of CO_2 have made the largest contribution to the increased anthropogenic forcing in every decade since the 1960s. The total aerosol ERF (aerosol–radiation interaction and aerosol–cloud interaction) has the strongest negative forcing (except for brief periods with large volcanic forcing), with a strengthening in the magnitude similar to many of the other anthropogenic forcing mechanisms with time. The global mean forcing of aerosol–radiation interactions was rather weak until 1950 but strengthened in the latter half of the last century and in particular in the period between 1950 and 1980. The RF due to aerosol–radiation interaction by aerosol component is shown in Section 8.3.4 (Figure 8.8).

Although there is *high confidence* for a substantial enhancement in the negative aerosol forcing in the period 1950–1980, there is much more uncertainty in the relative change in global mean aerosol forcing over the last two decades (1990–2010). Over the last two decades there has been a strong geographic shift in aerosol and aerosol precursor emissions (see Section 2.2.3), and there are some uncertainties in these emissions (Granier et al., 2011). In addition to the regional changes in the aerosol forcing there is also likely a competition between various aerosol effects. Emission data indicate a small increase in the BC emissions (Granier et al., 2011) but model studies also indicate a weak enhancement of other aerosol types. Therefore, the net aerosol forcing depends on the balance between absorbing and scattering aerosols for aerosol–radiation interaction as well as balance between the changes in aerosol–radiation and aerosol–cloud interactions. In the ACCMIP models, for example, the RF due to aerosol–radiation interaction becomes less negative during 1980 to 2000, but total aerosol ERF becomes more negative (Shindell et al., 2013c). There is a *very low confidence* for the trend in the total aerosol forcing during the past two to three decades, even the sign; however, there is *high confidence* that the offset from aerosol forcing to WMGHG forcing during this period was much smaller than over the 1950–1980 period.

The volcanic RF has a very irregular temporal pattern and for certain years has a strongly negative RF. There has not been a major volcanic eruption in the past decade, but some weaker eruptions give a current RF that is slightly negative relative to 1750 and slightly stronger in magnitude compared to 1999–2002 (see Section 8.4.2).

Figure 8.19 shows linear trends in forcing (anthropogenic, natural and total) over four different time periods. Three of the periods are the same as chosen in Box 9.2 (1984–1998, 1998–2011 and 1951–2011) and the period 1970–2011 is shown in Box 13.1. Monte Carlo simulations are performed to derive uncertainties in the forcing based on ranges given in Table 8.6 and the derived linear trends. Further, these uncertainties are combined with uncertainties derived from shifting time periods ±2 years and the full 90% confidence range is shown in Figure 8.19 (in Box 9.2 only the total forcing is shown with uncertainties derived from the forcing uncertainty without sensitivity to time period). For the anthropogenic forcing sensitivity to the selection of time periods is very small with a maximum contribution to the uncertainties shown in Figure 8.19 of 2%. However, for the natural forcing the sensitivity to time periods is the dominant contributor to the overall uncertainty (see Supplementary Material Figure 8.SM.3) for the relatively short periods 1998–2011 and 1984–1998, whereas this is not the case for the longer periods. For the 1998–2011 period the natural forcing is *very likely* negative and has offset 2 to 89% of the anthropogenic forcing. It is *likely* that the natural forcing change has offset at least 30% of the anthropogenic forcing increase and *very likely* that it has offset at least 10% of the anthropogenic increase. For the 1998–2011 period both the volcanic and solar forcings contribute to this negative natural forcing, with the latter dominating. For the other periods shown in Figure 8.19 the best estimate of the natural is much smaller in magnitude than the anthropogenic forcing, but note that the natural forcing is very dependent on the selection of time period near the 1984–1998 interval. Over the period 1951–2011 the trend in anthropogenic forcing is almost 0.3 W m^{-2} per decade and thus anthropogenic forcing over this period is more than 1.5 W m^{-2}. The anthropogenic forcing for 1998–2011 is 30% higher and with smaller uncertainty than for the 1951–2011 period. Note that due to large WMGHG forcing (Section 8.3.2) the anthropogenic forcing was similar in the late 1970s and early 1980s to the 1998–2011 period. The reason for the reduced uncertainty in the 1998–2011 anthropogenic forcing is the larger domination of WMGHG forcing and smaller contribution from aerosol forcing compared to previous periods. Similar to the results for 1970–2011 in Figure 8.19, Box 13.1 shows that the global energy budget is dominated by anthropogenic forcing compared to the natural forcing, except for the two major volcanic eruption in this period as can be easily seen in Figure 8.18.

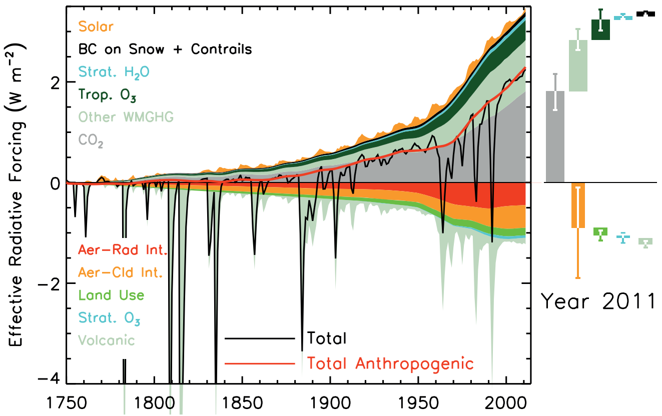


Figure 8.18 | Time evolution of forcing for anthropogenic and natural forcing mechanisms. Bars with the forcing and uncertainty ranges (5 to 95% confidence range) at present are given in the right part of the figure. For aerosol the ERF due to aerosol–radiation interaction and total aerosol ERF are shown. The uncertainty ranges are for present (2011 versus 1750) and are given in Table 8.6. For aerosols, only the uncertainty in the total aerosol ERF is given. For several of the forcing agents the relative uncertainty may be larger for certain time periods compared to present. See Supplementary Material Table 8.SM.8 for further information on the forcing time evolutions. Forcing numbers provided in Annex II. The total antropogenic forcing was 0.57 (0.29 to 0.85) W m^{-2} in 1950, 1.25 (0.64 to 1.86) W m^{-2} in 1980 and 2.29 (1.13 to 3.33) W m^{-2} in 2011.

Figure 8.20 shows the forcing between 1980 and 2011. Compared to the whole Industrial Era the dominance of the CO_2 is larger for this recent period both with respect to other WMGHG and the total anthropogenic RF. The forcing due to aerosols is rather weak leading

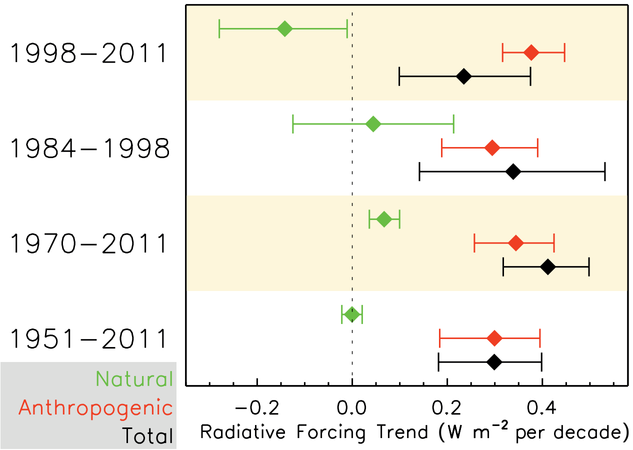


Figure 8.19 | Linear trend in anthropogenic, natural and total forcing for the indicated time periods. The uncertainty ranges (5 to 95% confidence range) are combined from uncertainties in the forcing values (from Table 8.6) and the uncertainties in selection of time period. Monte Carlo simulations were performed to derive uncertainties in the forcing based on ranges given in Table 8.6 and linear trends in forcing. The sensitivity to time periods has been derived from changing the time periods by ±2 years.

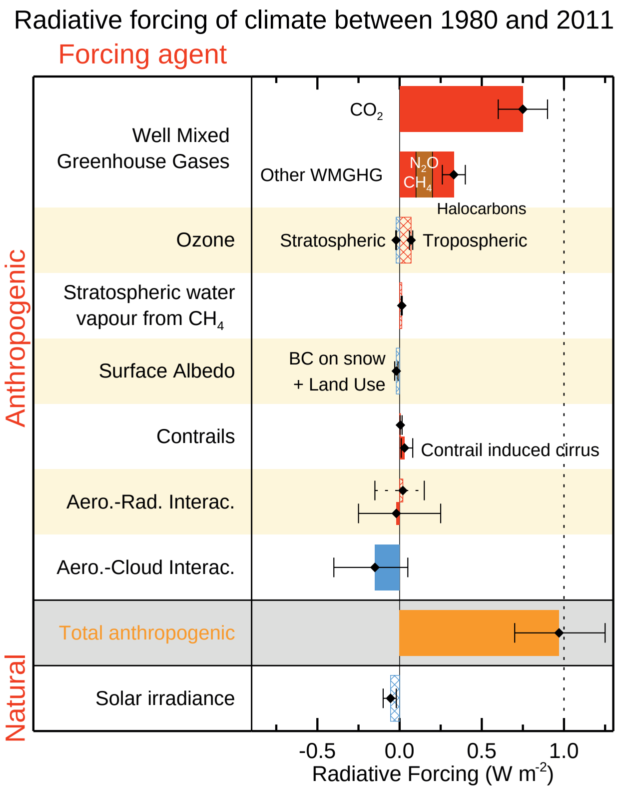


Figure 8.20 | Bar chart for RF (hatched) and ERF (solid) for the period 1980–2011, where the total anthropogenic ERF are derived from Monte-Carlo simulations similar to Figure 8.16. Uncertainties (5 to 95% confidence range) are given for RF (dotted lines) and ERF (solid lines).

to a very strong net positive ERF for the 1980–2011 period. More than 40% of the total anthropogenic ERF has occurred over the 1980–2011 period with a value close to 1.0 (0.7 to 1.3) W m^{-2}. The major contribution to the uncertainties in the time evolution of the anthropogenic forcing is associated with the aerosols (see Section 8.5.1). Despite this, anthropogenic ERF is *very likely* considerably more positive than the natural RF over the decadal time periods since 1950. This is in particular the case after 1980, where satellite data are available that provide important measurements to constrain the natural RF mechanisms (e.g., the volcanic RF change between 2007–2011 and 1978–1982 is 0.06 W m^{-2} and the representative change in solar irradiance over the 1980–2011 period is –0.06 W m^{-2}) with total natural RF of 0.0 (-0.1 to +0.1) W m^{-2}.

8.5.3 Future Radiative Forcing

Projections of global mean RF are assessed based on results from multiple sources examining the RF due to RCP emissions: the ACCMIP initiative (see Section 8.2) provides analysis of the RF or ERF due to aerosols and ozone (Shindell et al., 2013c), while WMGHG, land use and stratospheric water RFs are taken from the results of calculations with the reduced-complexity Model for the Assessment of Greenhouse-gas Induced Climate Change 6 (MAGICC6) driven by the RCP emissions and land use (Meinshausen et al., 2011a). While MAGICC6 also estimated ozone and aerosol RF, those values differ substantially from the ACCMIP values and are considered less realistic. Additional discussion of biases in the MAGICC6 results due to the simplified representations of atmospheric chemistry and the carbon cycle, along with further discussion on the representativeness of the RCP projections in context with the broader set of scenarios in the literature, is presented in Section 11.3.5 and Section 12.3 (also see Section 8.2). As the ACCMIP project provided projected forcings primarily at 2030 and 2100, we hereafter highlight those times. Although understanding the relative contributions of various processes to the overall effect of aerosols on forcing is useful, we emphasize the total aerosol ERF, which includes all aerosol–radiation and aerosol–cloud interactions, as this is the most indicative of the aerosol forcing driving climate change. We also present traditional RF due to aerosol–radiation interaction (previously called direct aerosol effect) but do not examine further the various components of aerosol ERF. Aerosol forcing estimates, both mean and uncertainty ranges, are derived from the 10 ACCMIP models, 8 of which are also CMIP5 models. We analyze forcing during the 21st century (relative to 2000), and hence the WMGHG forcing changes are in addition to persistent forcing from historical WMGHG increases.

Analysis of forcing at 2030 relative to 2000 shows that under RCP2.6, total ozone (tropospheric and stratospheric) forcing is near zero, RF due to aerosol–radiation interaction is positive but small, and hence WMGHG forcing dominates changes over this time period (Figure 8.21). WMGHG forcing is dominated by increasing CO_2, as declining CH_4 and increasing N_2O have nearly offsetting small contributions to forcing. Aerosol ERF was not evaluated for this RCP under ACCMIP, and values cannot be readily inferred from RF due to aerosol–radiation interaction as these are not directly proportional. Under RCP8.5, RF due to aerosol–radiation interaction in 2030 is weakly negative, aerosol ERF is positive with a fairly small value and large uncertainty range, total ozone forcing is positive but small (~0.1 W m^{-2}), and thus WMGHG forcing again dominates with a value exceeding 1 W m^{-2}. As with RCP2.6, WMGHG forcing is dominated by CO_2, but under this scenario the other WMGHGs all contribute additional positive forcing. Going to 2100, ozone forcing diverges in sign between the two scenarios, consistent with changes in the tropospheric ozone burden (Figure 8.4) which are largely attributable to projected CH_4 emissions, but is small in either case. Ozone RF is the net impact of a positive forcing from stratospheric ozone recovery owing to reductions in anthropogenic ozone-depleting halocarbon emissions in both scenarios and a larger impact from changes in tropospheric precursors (Shindell et al., 2013c) which have a negative forcing in RCP2.6 and a positive forcing in RCP8.5.

The two scenarios are fairly consistent in their trends in RF due to aerosol–radiation interaction by component (Figure 8.21). There is positive RF due to aerosol–radiation interaction due to reductions in sulfate aerosol. This is largely offset by negative RF due to aerosol–radiation interaction by primary carbonaceous aerosols and especially by nitrate (though nearly all CMIP5 models did not include nitrate), leaving net aerosol RF due to aerosol–radiation interaction values that are very small, 0.1 W m^{-2} or less in magnitude, in either scenario at 2030 and 2100. Nitrate aerosols continue to increase through 2100 as ammonia emissions rise steadily due to increased use of agricultural fertilizer even as all other aerosol precursor emissions decrease (Figure 8.2), including sulphur dioxide which drives the reduction in sulphate aerosol that also contributes to additional formation of nitrate aerosols in the future (Bauer et al., 2007; Bellouin et al., 2011). Aerosol ERF is *likely* similar at this time in all scenarios given that they all have greatly reduced emissions of all aerosols and aerosol precursors other than ammonia. Aerosol ERF shows a large positive value at 2100 relative to 2000, nearly returning to its 1850 levels (the 2100 versus 1850 ERF represents a decrease in ERF of 91% relative to the 2000 versus 1850 value), as is expected given the RCP emissions. Thus although some models project large increases in nitrate RF in the future, the reduction in overall aerosol loading appears to lead to such a strong reduction in aerosol ERF that the impact of aerosols becomes very small under these RCPs. Of course the projections of drastic reductions in primary aerosol as well as aerosol and ozone precursor emissions may be overly optimistic as they assume virtually all nations in the world become wealthy and that emissions reductions are directly dependent on wealth. The RCPs also contain substantially lower projected growth in HFC emissions than in some studies (e.g., Velders et al., 2009).

Although aerosol ERF becomes less negative by nearly 1 W m^{-2} from 2000 to 2100, this change is still small compared with the increased WMGHG forcing under RCP8.5, which is roughly 6 W m^{-2} during this time (Figure 8.21). Roughly 5 W m^{-2} of this WMGHG forcing comes from CO_2, with substantial additional forcing from increases in both CH_4 and nitrous oxide and only a very small negative forcing from reductions in halocarbons. Under RCP2.6, the WMGHG forcing is only about 0.5 W m^{-2} during this time, as relatively strong decreases in CH_4 and halocarbon forcing offset roughly 40% of the increased CO_2 forcing, which is itself far less than under RCP8.5. Hence under this scenario, the projected future forcing due to aerosol reductions is actually stronger than the WMGHG forcing. Viewing the timeseries of the various forcings, however, indicates that aerosol ERF is returning to its pre-industrial levels, so that net forcing becomes increasingly dominated by WMGHGs regardless of scenario during the 21st century (Figure 8.22). As the forcing is so heavily dominated by WMGHGs at 2100, and the WMGHG concentrations (CO_2) or emissions (others) were chosen to match forcing targets, all the scenarios show net forcing values at that time that are fairly close to the scenarios' target values. The reduced aerosol forcing, with its large uncertainty, leads to a pronounced decrease in the uncertainty of the total net forcing by 2100. Based on the spread across ACCMIP models (using ERF for aerosols and converting to ERF for GHGs), the 90% confidence interval (CI) is about 20% for the 2100 net forcing, versus 26% for 2030 under RCP8.5 and 45–61% for 1980 and 2000 (Shindell et al., 2013c). The total ERF due to all causes has been independently estimated based on the transient response in the CMIP5 models and a linear forcing-response relationship derived through regression of the modelled response to an instantaneous increase in CO_2 (Forster et al., 2013). Uncertainties based on model spread behave similarly, with the 90% CI for net total ERF decreasing from 53% for 2003 to only 24 to 34% for 2100. Forcing relative to 2000 due to land use (via albedo only) and stratospheric water vapor changes are not shown separately as their projected values under the four RCPs are quite small: –0.09 to 0.00 and –0.03 to 0.10 W m^{-2}, respectively.

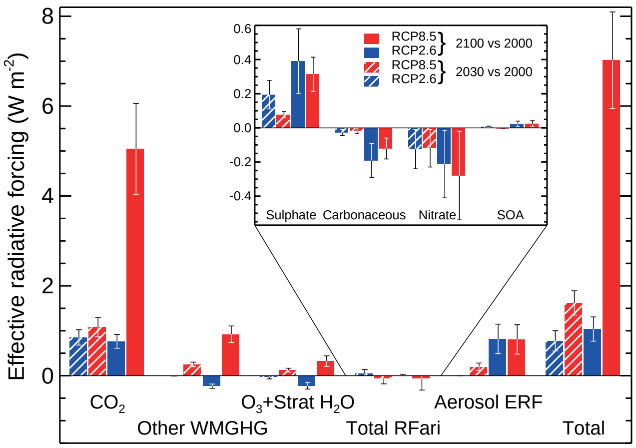


Figure 8.21 | Radiative forcing relative to 2000 due to anthropogenic composition changes based on ACCMIP models for aerosols (with aerosol ERF scaled to match the best estimate of present-day forcing) and total ozone and RCP WMGHG forcings. Ranges are one standard deviation in the ACCMIP models and assessed relative uncertainty for WMGHGs and stratospheric water vapor. Carbonaceous aerosols refer to primary carbonaceous, while SOA are secondary organic aerosols. Note that 2030 ERF for RCP2.6 was not available, and hence the total shown for that scenario is not perfectly comparable to the other total values. RFari is RF due to aerosol–radiation interaction.

The CMIP5 forcing estimates (Forster et al., 2013) for the total projected 2030 and 2100 ERF are slightly smaller than the results obtained from the ACCMIP models (or the RCP targets; see Section 12.3.3). Examining the subset of models included in both this regression analysis and in ACCMIP shows that the ACCMIP subset show forcings on the low side of the mean value obtained from the full set of CMIP5 analyzed, indicating that the discrepancy between the methods is not related to analysis of a different set of models. Instead, it may reflect nonlinearities in the response to forcing that are not represented by the regression analysis of the response to abrupt CO_2 increase experiments (Long and Collins, 2013) or differences in the response to other forcing agents relative to the response to CO_2 used in deriving the CMIP5 estimates (see also 12.3.3).

Natural forcings will also change in the future. The magnitudes cannot be reliably projected, but are *likely* to be small at multi-decadal scales (see Section 8.4). Brief episodic volcanic forcing could be large, however.

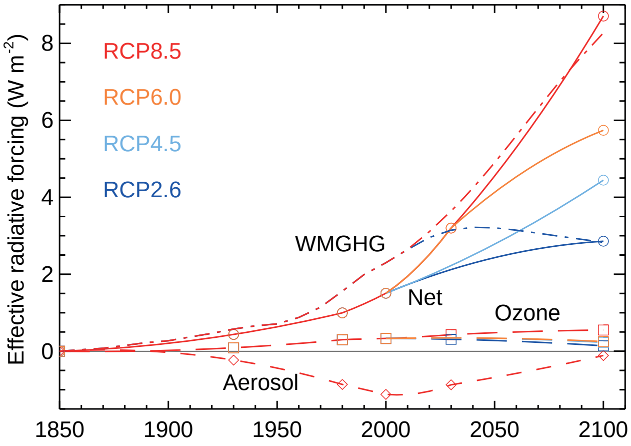


Figure 8.22 | Global mean anthropogenic forcing with symbols indicating the times at which ACCMIP simulations were performed (solid lines with circles are net; long dashes with squares are ozone; short dashes with diamonds are aerosol; dash-dot are WMGHG; colours indicate the RCPs with red for RCP8.5, orange RCP6.0, light blue RCP4.5, and dark blue RCP2.6). RCPs 2.6, 4.5 and 6.0 net forcings at 2100 are approximate values using aerosol ERF projected for RCP8.5 (modified from Shindell et al., 2013c). Some individual components are omitted for some RCPs for visual clarity.

8.6 Geographic Distribution of Radiative Forcing

The forcing spatial pattern of the various RF mechanisms varies substantially in space and in time, especially for the NTCFs. The spatial pattern is of interest to the extent that it may influence climate response (Section 8.6.2.2) as is being particularly investigated in the ACCMIP simulations.

8.6.1 Spatial Distribution of Current Radiative Forcing

The WMGHGs such as CO_2 have the largest forcing in the subtropics, decreasing toward the poles, with the largest forcing in warm and dry regions and smaller values in moist regions and in high-altitude regions (Taylor et al., 2011). For the NTCFs (Box 8.2) their concentration spatial pattern and therefore their RF pattern are highly inhomogeneous, and again meteorological factors such as temperature, humidity, clouds, and surface albedo influence how concentration translates to RF.

Figure 8.23 shows the RF spatial distribution of the major NTCFs together with standard deviation among the ACCMIP models (Shindell et al., 2013c) the net anthropogenic composition (WMGHG+ozone+aerosol) forcing is also shown (lower left panel). These models used unified anthropogenic emissions of aerosol and ozone precursors (Supplementary Material Figure 8.SM.2), so that the model diversity in RF is due only to differences in model chemical and climate features and natural emissions, and would be larger if uncertainty in the anthropogenic emissions were also included. In general, the confidence in geographical distribution is lower than for global mean, due to uncertainties in chemistry, transport and removal of species.

The negative RF due to aerosol–radiation interaction (first row; defined in Figure 7.3) is greatest in the NH and near populated and biomass burning regions. The standard deviation for the net RF due to aerosol–radiation interaction is typically largest over regions where vegetation changes are largest (e.g., South Asia and central Africa), due to uncertainties in biomass burning aerosol optical properties and in treatment of secondary organic aerosols. Carbonaceous aerosol forcing (second row) is greatest in South and East Asia and can be negative in biomass burning regions due to large weakly absorbing organic components. Absorbing aerosols also have enhanced positive forcing when they overlie high albedo surfaces such as cryosphere, desert or clouds, with as much as 50% of BC RF resulting from BC above clouds (Zarzycki and Bond, 2010).

Figure 8.24 compares the aerosol RFs for ACCMIP (Shindell et al., 2013c), which are representative of the CMIP5 experiments, with those from the AeroCom model intercomparison (Myhre et al., 2013) which includes sixteen models that used unified meteorology and are more extensively compared to measurements (e.g., Koch et al., 2009b; Koffi et al., 2012). The forcing results are very similar, establishing the representativeness and validity of the ACCMIP aerosol simulations.

The net aerosol ERF (Figure 8.23; third row), includes both aerosol–radiation and aerosol–cloud interactions. The spatial pattern correlates with the RF (first row), except with stronger effect in the outflow regions over oceans. The flux change is larger in the NH than the SH (e.g., by nearly a factor of 3; Ming et al., 2007). Rapid adjustment associated with aerosol–radiation and aerosol–cloud interactions may enhance or reduce cloud cover depending on the region, cloud dynamics and aerosol loading (e.g., Randles and Ramaswamy, 2008; Koch and Del Genio, 2010; Persad et al., 2012). In general, the ocean-land forcing pattern differs from that reported in AR4, where the forcing due to aerosol–cloud interaction were larger over land than ocean (Forster et al., 2007), and this continues to be a source of uncertainty. Since AR4, Quaas et al. (2009) showed using satellite retrievals that the correlation between AOD changes and droplet number changes is stronger over oceans than over land and that models tend to overestimate the strength of the relation over land. Penner et al. (2011) showed that satellite retrievals, due to their dependence on present-day conditions, may underestimate the forcing due to aerosol–cloud interaction, especially over land, although this model analysis may overestimate the cloud condensation nucleus to AOD relation (Quaas et al., 2011). Wang and Penner (2009) also showed that if models include boundary layer nucleation and increase the fraction of sulphur emitted as a primary particle, the effect over land is increased relative to over ocean (see also Section 7.5.3). The aerosol ERF standard deviation is large in biomass burning regions, as for the RF, and in regions where cloud effects differ among models (e.g., northern North America, northeast Asia, Amazonia). The spread in aerosol ERF is much larger than for the RF alone, although the relative standard deviation is no larger (Shindell et al., 2013c).

For components that primarily scatter radiation, the radiative effect at the surface is similar to the RF (according to the definition in Section 8.1.1). However for components that absorb radiation in the atmosphere the radiation reaching the surface is reduced (Forster et al., 2007; Ramanathan and Carmichael, 2008; Andrews et al., 2010). This absorption of incoming solar radiation alters the vertical temperature profile in the atmospheric column and can thus change atmospheric circulation and cloud formation. The aerosol atmospheric absorption (Figure 8.23, bottom right), or the difference between ERF and the analogous radiative flux reaching the surface including rapid adjustments, has a spatial pattern that to lowest order tracks the carbonaceous aerosol forcing, but is also affected by cloud changes, where e.g., cloud loss could enhance atmospheric absorption. Atmospheric aerosol absorption patterns thus mirror the ERF due to aerosol–cloud interaction pattern, with larger forcing over continents.

Ozone RF is calculated using the methodology described in Shindell et al. (2013c), but applied to the larger set of models in ACCMIP (Stevenson et al., 2013). The net ozone RF (Figure 8.23; fourth row) is largest in subtropical latitudes, and is more positive in the NH than the SH. Pollution in the NH accounts for positive tropospheric forcing; stratospheric ozone loss has caused negative SH polar forcing. Model standard deviation is largest in the polar regions where lower stratosphere/upper troposphere changes differ in the models (Young et al., 2013).

Overall, the *confidence* in aerosol and ozone RF spatial patterns is *medium* and lower than that for the global mean due to the large regional standard deviations (Figure 8.23), and is exacerbated in aerosol ERF patterns due to uncertainty in cloud responses.

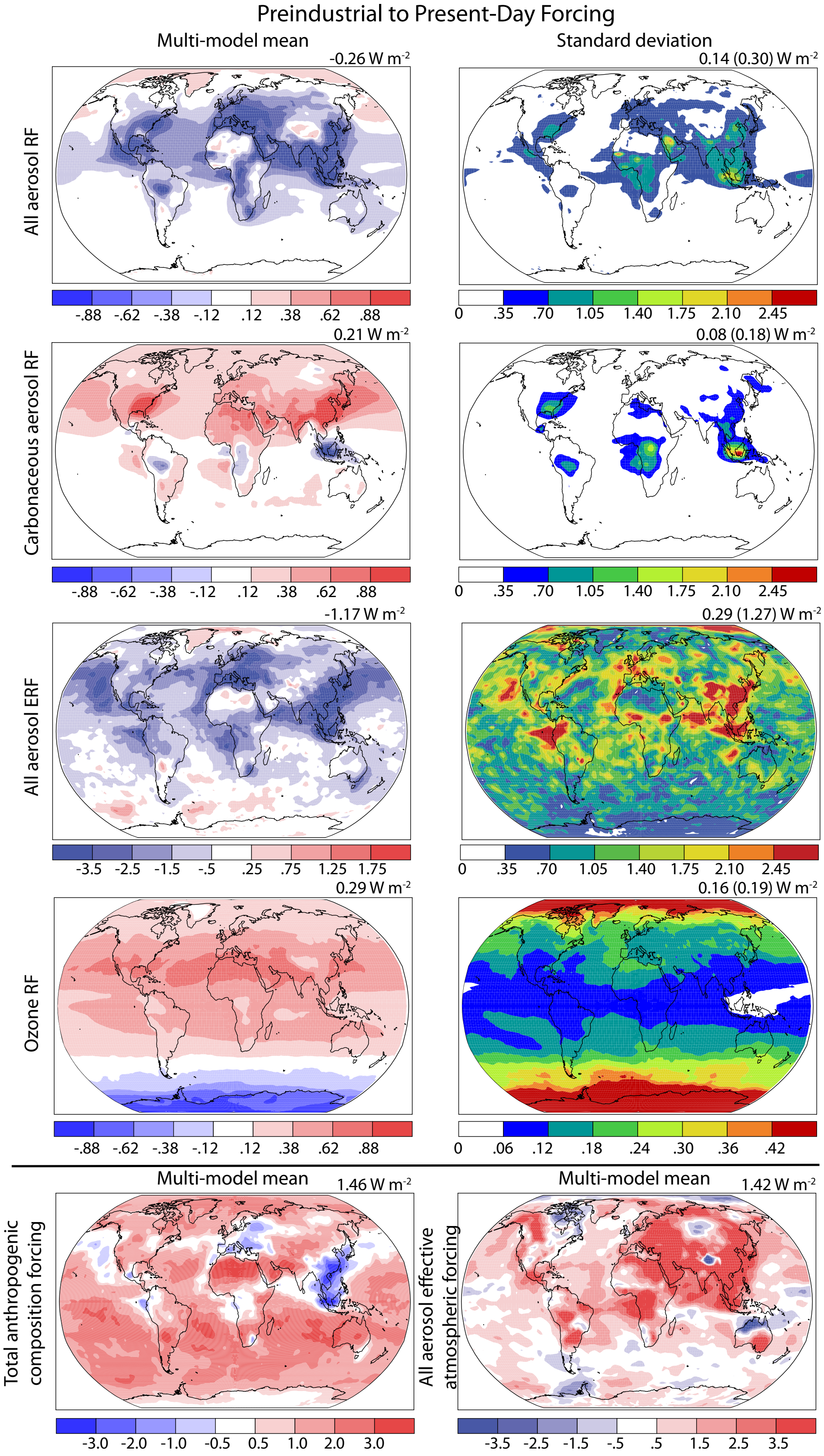


Figure 8.23 | Spatial pattern of ACCMIP models 1850 to 2000 forcings, mean values (left) and standard deviation (right) for aerosols and ozone (top four rows). Values above are the average of the area-weighted global means, with the area weighted mean of the standard deviation of models at each point provided in parenthesis. Shown are net aerosol RF due to aerosol–radiation interaction (top, 10 models), carbonaceous aerosol RF due to aerosol-radiation interaction (2nd row, 7 models), aerosol ERF (3rd row, 8 models), ozone (4th row, 11 models), total anthropogenic composition forcing (WMGHG+ozone+aerosols; bottom left), aerosol atmospheric absorption including rapid adjustment (bottom right, 6 models). Note that RF and ERF means are shown with different colour scales, and standard deviation colour scales vary among rows.

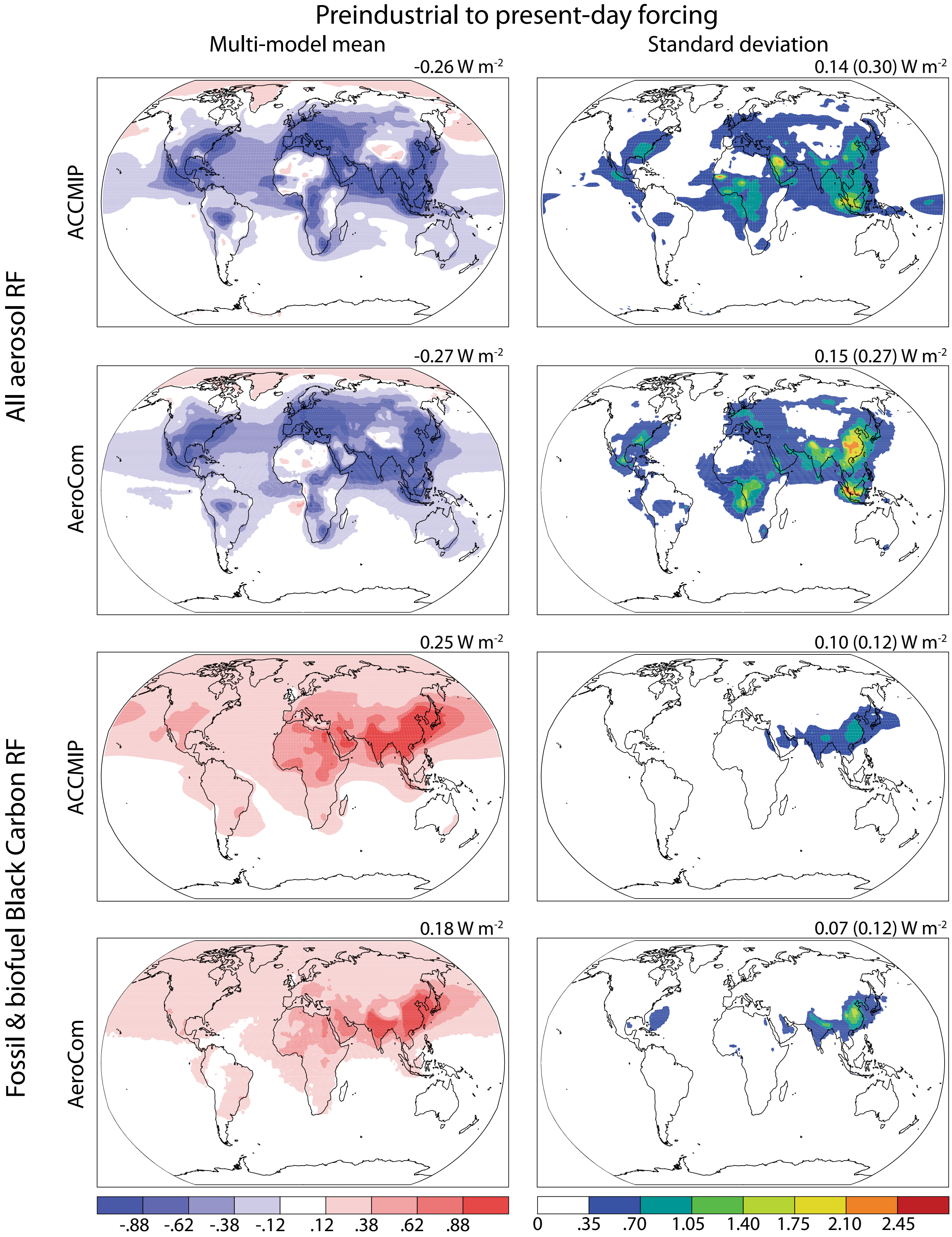


Figure 8.24 | Spatial pattern of ACCMIP and 16 AeroCom models 1850 to 2000 RF due to aerosol–radiation interaction, mean values (left) and standard deviation (right). Note that different carbonaceous aerosol diagnostics are used here compared to Figure 8.23, due to available AeroCom fields. Values above are the average of the area-weighted global means, with the area weighted mean of the standard deviation of models at each point provided in parentheses.

8.6.2 Spatial Evolution of Radiative Forcing and Response over the Industrial Era

8.6.2.1 Regional Forcing Changes During the Industrial Era

The spatial distribution of the WMGHG RF has shifted only slightly over the industrial period; however the RF spatial distributions for NTCFs has shifted with emissions, due to the timing of regional development and implementation of pollution standards (Supplementary Material Figures 8.SM.1 and 8.SM.2 show regional trends and emissions maps; Lamarque et al., 2013). Figure 8.25 shows how the distributions of aerosol and ozone forcings are modelled to have changed up to 1930, 1980 and 2000. Substantial industrial coal-burning in the early part of the 20th century occurred in the northeastern United States and Western Europe, leading to stronger sulphate and BC forcing near those regions (Figure 8.25, left). Between 1950 and 1970, coal burning for power generation increased while coal burning for other purposes was replaced by oil and natural gas and motor vehicle usage grew rapidly in these regions, leading to more sulphate and less BC. Peak aerosol forcing in North America and Europe occurred around 1970–1980 (Figure 8.25, second column), while Asian development led to increased biofuel and fossil fuel sources of aerosols and ozone precursors toward the end of the century. During the final decades of the century, desulphurization controls reduced sulphur emissions from North America and Europe, resulting in reduced negative forcing in these regions and positive Arctic aerosol forcing. The SH ozone hole developed during the final three decades, with negative forcing over high latitudes. Biomass burning generated ozone and carbonaceous aerosols in NH high-latitudes early in the century, with increased tropical burning from mid to late century.

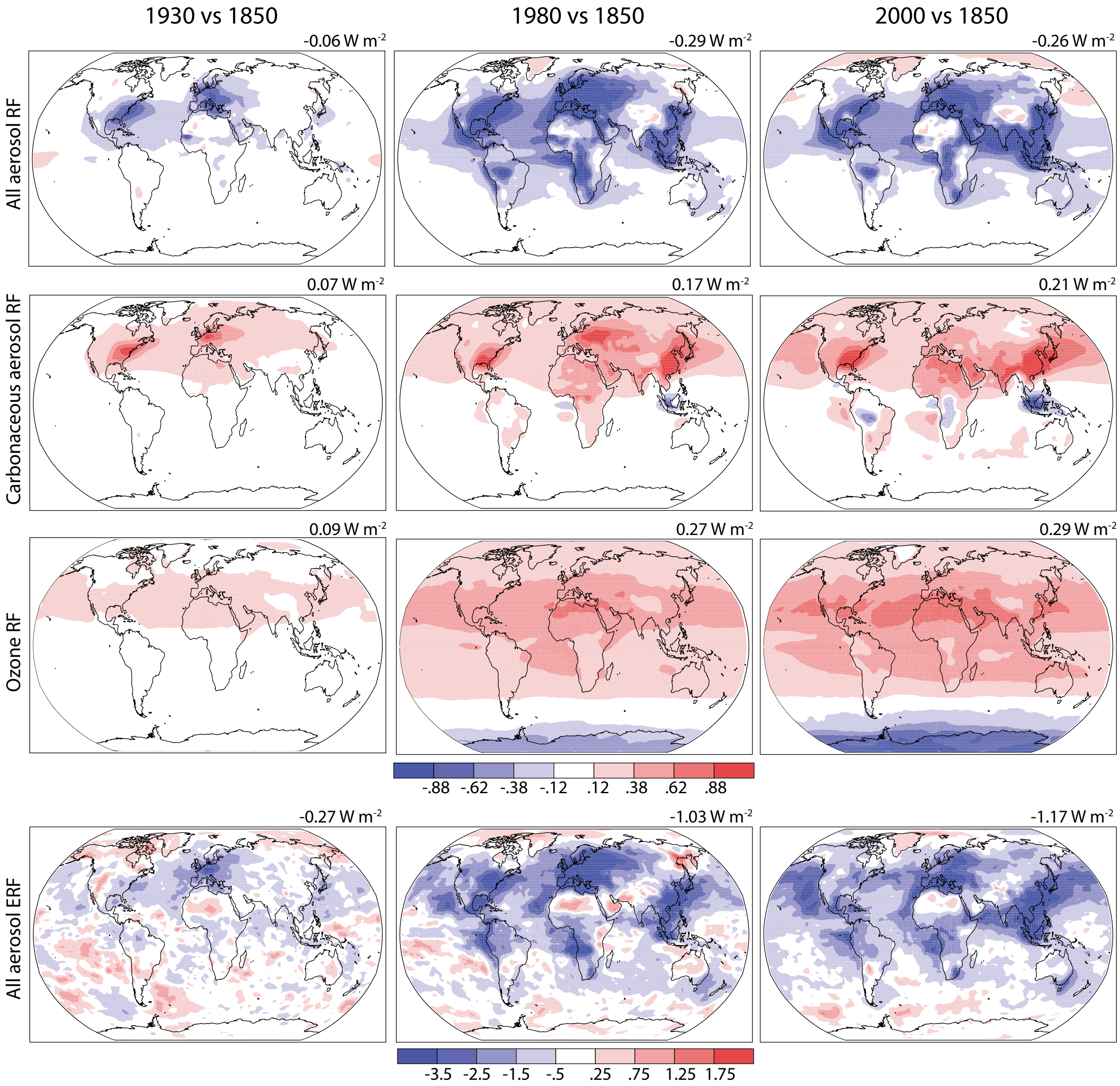


Figure 8.25 | Multi-model mean RF due to aerosol–radiation interaction of all aerosols, carbonaceous aerosols, ozone, and aerosol ERF (W m^{-2}) for the indicated times based on the ACCMIP simulations. Global area-weighted means are given in the upper right.

Aerosol ERF grew rapidly from 1930 to 1980, as did RF due to aerosol–radiation interaction, with a spatial structure reflecting both the influence of aerosol–radiation and aerosol–cloud interactions that are especially strong over pollution outflow regions and over areas with high surface albedo. From 1980 to 2000, aerosol ERF continued to become more negative even as negative RF due to aerosol–radiation interaction grew weaker, with the spatial pattern showing strengthening of aerosol ERF over Asia and weakening of aerosol ERF over North America and Europe.

Soil dust has changed since the pre-industrial due to land disturbance and resulting desertification (a forcing) and to changes in climate (a feedback). Mahowald et al. (2010) showed approximate doubling in dust loading over the 20th century (–0.1 W m^{-2}; consistent with the best estimate in Section 7.5.2; Section 8.3.4.2), primarily from the Saharan and Middle Eastern Deserts, with largest increase from the 1950s to the 1980s (–0.3 W m^{-2}), followed by a leveling. The increased dustiness reduces model precipitation within the Saharan source region, improving agreement with observed precipitation.

Aerosol loading changes during the past century have impacted radiation at the surface (Section 2.3.3), with peak radiation reductions in North America and Europe in the 1980s, and ongoing reduction in South and East Asia (Wild, 2009). The AR4 and CMIP5 models simulated these trends but underestimated their magnitude, the decadal temperature variations and the diurnal temperature range over land (Wild, 2009; see Chapter 9).

Changes in spatial patterns of species and their forcing over the century are difficult to validate due to sparse observations of short-lived species. Some constraint comes from limited historical observations in ice core records and from shorter trends beginning in late century from satellite and surface-based site measurements. The emissions estimates for historical species are very uncertain, especially for carbonaceous aerosols and dust. Therefore, the *confidence* in the historical forcing pattern changes is *low* for RF due to aerosol–radiation interaction and ozone, and *very low* for ERF, carbonaceous aerosols and dust.

8.6.2.2 Relationship Between Regional Forcing Patterns and Climate Response During the Industrial Era

An increasing body of research considers how spatial variations in RF affect climate response. Detection and attribution methods have had limited success in discerning statistically significant regional climate signals from regional forcing, due to large internal climate variability at regional scales, uncertainty in model processes and sparse regional observational records (Chapter 10). Meanwhile, research including model sensitivity studies for NTCFs, which vary strongly in space in time, explores climate response patterns.

In AR4 (Forster et al., 2007; Knutti et al., 2008) it was argued that the spatial pattern of forcing is not indicative of the pattern of climate response. Rather, the response is linked more closely to TOA flux resulting from the climate feedback spatial patterns (Boer and Yu, 2003; Taylor et al., 2011; Ming and Ramaswamy, 2012), with the lapse rate, surface albedo and cloud feedbacks explaining most of the temperature response. Yet Crook and Forster (2011) showed that both the spatial distribution of climate feedbacks and of heterogeneous forcing played important roles in the patterns of 20th century temperature changes. Other studies since AR4 have probed relationships between forcing patterns and climate responses.

Broad links between forcing and climate response have been identified. Shindell et al. (2010) used multiple models to show that surface temperature changes are much more sensitive to latitudinal than longitudinal variations in forcing. Shindell and Faluvegi (2009) used a model inverse approach to infer that NH aerosol reduction was associated with more than 70% of Arctic warming from the 1970s to the 2000s, and that Arctic and much of the SH surface temperature changes are strongly affected by remote forcing changes (alsoSection 10.3.1.1.4). Voulgarakis and Shindell (2010) defined a regional transient temperature sensitivity parameter, or temperature response per unit forcing for each 4-degree latitude band. Using observed surface air temperature changes they showed that the parameter is best constrained from 50°S to 25°N, where the value is 0.35°C (W $m^{-2})^{-1}$, smaller than at northern higher latitudes, and 35% smaller than in AR4 models.

Some aerosol model studies have demonstrated highly localized climate response to regional forcing. Significant regional cooling and hydrological shifts in the eastern USA and in Eastern Asia during the last half of the 20th century were modelled and attributed to local aerosols (Leibensperger et al., 2008, 2012a, 2012b; Chang et al., 2009) and localized warming projected for aerosol reductions (Mickley et al., 2012). Observations have also linked historical trends in aerosols and temperature (Ruckstuhl et al., 2008; Philipona et al., 2009).

Since AR4, there has been new research on aerosol influences on the hydrologic cycle (also Sections 7.4, 7.6.4, 10.3.3.1 and 11.3.2.4.3). Increased aerosol loading, with greater surface energy flux reduction in the NH, has been implicated in the observed southward shift of the Intertropical Convergence Zone (ITCZ) towards the hemisphere with smaller surface energy reduction: southward up to the 1980s with a reversal since (e.g., Denman et al., 2007; Zhang et al., 2007). Several studies have modelled an associated reduction in NH precipitation and associated shifts in the Hadley circulation (e.g., Rotstayn et al., 2000; Williams et al., 2001; Ming et al., 2011). The ITCZ shift may in turn be responsible for broad regional precipitation changes, including drying of the Sahel (e.g., Rotstayn and Lohmann, 2002; Biasutti and Giannini, 2006; Kawase et al., 2010; Ackerley et al., 2011) and northwestern Brazil (Cox et al., 2008), both of which peaked in the 1980s. These hemispheric asymmetric ITCZ effects are overlaid on thermodynamic aerosol effects which moisten subtropical regions, countering GHG-induced drying of these regions (Ming et al., 2011). Studies indicate that aerosols are more effective than an equivalent WMGHG forcing for shifting precipitation, and that historical trends in several areas cannot be explained without including aerosol forcing (Bollasina et al., 2011; Booth et al., 2012; Shindell et al., 2012a; Shindell et al., 2012b). However, *confidence* in attribution of any human influence on zonal shifts in precipitation distribution is only *medium* (Section 10.3.2.2).

There is increasing evidence but limited agreement that absorbing aerosols influence cloud distributions (Section 7.3.4.2). Absorbing aerosols apparently have complex influences on precipitation in monsoon regions. Model studies of Stephens et al. (2004) and Miller et al. (2004) showed that dust absorption over Africa enhances low-level convergence, vertical velocities and therefore local monsoon circulation and precipitation. On the other hand, Kawase et al. (2010) showed that biomass burning BC may cause the decreasing precipitation trend seen in tropical Africa during austral summer, due to reduction in evaporation and enhanced subsidence. The aerosol effects on the Indian monsoon are similarly complex, and have been the subject of numerous studies (e.g., Ramanathan et al., 2005; Chung and Ramanathan, 2006; Lau et al., 2006; Wang et al., 2009; Bollasina et al., (2011), but a clear picture of how the regional aerosol forcing correlates with responses has not yet fully emerged. Attribution of changes in monsoon to human influence generally has *low confidence* (Section 10.3).

Stratospheric ozone loss modelling has demonstrated an effect on the SH stratosphere similar to increased GHGs, cooling stratospheric temperatures, strengthening the polar vortex and shifting the westerly jet poleward; however causing cooler Antarctic surface temperatures, with larger influence on austral summer conditions (Son et al., 2009; McLandress et al., 2011; Thompson et al., 2011; see also Sections 10.3.3 and 11.3.2.4.3.) In the troposphere, models indicate that increased tropospheric ozone has caused warming, proportionally more in the NH and notably to the Arctic during winter, mainly during the second half of the 20th century (Shindell et al., 2006a).

Albedo changes due to land use and land cover changes exert a heterogeneous climate forcing (Figure 8.9). The surface albedo brightened on the one hand due to a shift from forest to brighter croplands, causing local cooling (e.g., Eliseev and Mokhov, 2011; Lee et al., 2011), but also darkened due to the re-expansion of forests to higher latitudes (Esper and Schweingruber, 2004) and increased vegetation height in snowy regions (Bonfils et al., 2012; also Section 8.3.5). Model studies have shown cooling from land use and land cover changes, especially over NH continents, although without demonstrating a detectable signal in observations (Matthews et al., 2004).

In addition to land use and climate-induced vegetation changes, CO_2 affects vegetation forcing indirectly, reducing transpiration from plants as stomata open less with increasing CO_2, resulting in localized atmospheric drying and warming (Section 11.3.2.3.1; Joshi and Gregory, 2008). These are not included in the standard RF (Section 8.1) and may be considered feedbacks (Section 8.3.2). This is modelled to be largest over the Amazon, the central African forest, and to some extent over boreal and temperate forests (Andrews et al., 2011). In the coupled climate modelling study of Lawrence and Chase (2010), the vegetation changes caused significant reduction in evapotranspiration, drying and warming in tropical and subtropical regions, with insignificant cooling at higher latitudes. Overall, vegetation changes may have caused modest cooling at high latitudes and warming at low latitudes, but the uncertainties are large and *confidence* is *very low*.

Deposition of BC on snow and ice, and loss of snow and ice darken the surface, reduces albedo, and enhances climate warming. Substantial snow-cover reduction of North America leads to warmer North American summertime temperature in models having a strong snow albedo feedback. These forcings can also have non-local impacts that result from enhanced land-ocean temperature contrast, increasing surface convergence over land and divergence over oceans. A poleward intensification of the high pressure patterns and subtropical jet may also result (Fletcher et al., 2009). BC contributions to snow darkening reduces snow cover, however the magnitude of the effect is very uncertain (see Sections 7.5.2.3 and 8.3.4.4). A model study calculated BC-albedo reduction to cause about 20% Arctic snow/ice cover reduction and 20% of Arctic warming over the previous century (Koch et al., 2011). However, reductions in Arctic soot during the past two decades (e.g., Hegg et al., 2009) have *likely* reversed that trend (e.g., Koch et al., 2011; Skeie et al., 2011b; Lee et al., 2013). Cryospheric feedbacks and atmospheric dynamical responses in models have an associated poleward shift in the temperature response to aerosol–cloud interactions (Kristjansson et al., 2005; Koch et al., 2009a; Chen et al., 2010).

Solar spectral (UV) irradiance variations along the solar cycle induce ozone responses by modifying the ozone production rate through photolysis of molecular oxygen (Section 8.4.1.4.1), and the resulting differential heating can drive circulation anomalies that lead to regional temperature and precipitation changes (Haigh, 1999; Shindell et al., 2006b; Frame and Gray, 2010; Gray et al., 2010). Such solar forcing may influence natural modes of circulation such as the Northern Annular Mode (e.g., Shindell et al., 2001; de la Torre et al., 2006; Ineson et al., 2011), the South Asian Summer Monsoon (Fan et al., 2009), the Southern Annular Mode (Kuroda and Kodera, 2005; Roscoe and Haigh, 2007) or the ENSO (Mann et al., 2005). The pattern of temperature response is less uniform than the forcing, for example, warming in the NH, but little response in the SH due to temperature moderation by wind speed enhancement effects on ocean circulation (Swingedouw et al., 2011). Regional responses to solar forcing are mediated by the stratosphere, so that reproducing such change requires spectrally varying solar forcing rather than TSI forcing (Lee et al., 2009; Section 8.4.1.4).

Stratospheric aerosol clouds (also Section 8.4.2.2) from tropical eruptions spread poleward and can cover an entire hemisphere or the globe, depending on the initial latitudinal spread. The aerosol eruption cloud from the 1963 Agung was confined mainly to the SH; the 1982 El Chichón mainly to the NH; and the 1991 Pinatubo covered the globe, all with an *e*-folding lifetime of about 1 year (e.g., Antuña et al., 2003). High-latitude eruptions typically stay confined to the high-latitude regions with shorter lifetimes of 2 to 4 months (Kravitz and Robock, 2011). Volcanic aerosols primarily scatter solar radiation back to space, but also absorb longwave radiation with the former larger by an order of magnitude. Stratospheric aerosol absorption heats the layer where they reside and produces distinct vertical and horizontal distributions of the heating rate. The temperature and chemical effects of the aerosols also enhance ozone destruction, which somewhat counteracts the radiative heating (Stenchikov et al., 2002). For tropical eruptions, this may affect atmospheric dynamics, with a stronger polar vortex, a positive mode of the Arctic Oscillation, and winter warming over NH continents (Robock, 2000). Climate responses to solar and volcanic forcings are further discussed in the context of detection and attribution of millennial climate change (see Section 10.7).

The study of how climate responds to regionally varying patterns of forcing is critical for understanding how local activities impact regional climate; however, the studies are exploratory and generally evoke *very low confidence*. However there is *medium* to *high confidence* in some qualitative but robust features, such as the damped warming of the NH and shifting of the ITCZ from aerosols, and positive feedbacks from high-latitude snow and ice albedo changes.

8.6.3 Spatial Evolution of Radiative Forcing and Response for the Future

Most components of aerosols and ozone precursors are estimated to decrease toward the end of this century in the RCPs except CH_4 in RCP8.5 (Figure 8.2) and nitrate aerosols, though some species reach the maximum amounts of emissions around the mid-21st century (Figure 8.2). The RCPs therefore contrast with the emission scenarios for TAR and AR4, which were based on Special Report on Emissions Scenarios (SRES) and have future projections of larger increase in the near-term climate forcers (NTCFs). It has been questioned whether such low emission of NTCFs is possible in the future given the current policies (Pozzer et al., 2012). This section surveys spatial differences in the RF of aerosols and ozone for the future based on the RCPs.

Figure 8.26 shows the global distributions of changes in aerosol and ozone forcings in 2030 and 2100 relative to 2000 for RCP2.6 and 8.5 (Shindell et al., 2013c). Both scenarios indicate reduced aerosol loading, and thus positive forcing over Europe, North America and Asia by 2100 where RF is above +0.5 W m^{-2} because of substantial reduction of scattering aerosols. The global mean RF due to aerosol–radiation interaction is estimated to be +0.12 and +0.08 W m^{-2} for RCP2.6 and 8.5, respectively, in 2100. Though the RF by total anthropogenic aerosols is positive, reduced BC contributes substantial negative forcing especially over the similar regions. The global mean carbonaceous RF including both the effects of BC and OC is estimated to be –0.20 and –0.11 W m^{-2} for RCP2.6 and 8.5, respectively, in 2100. Early in the century, on the other hand, both scenarios indicate increased negative aerosol forcing over South Asia, with reversal between 2030 and 2100. Emissions of BC, OC and SO_2 will reach their maximums early and middle in the century for RCP2.6 and 8.5, respectively in India. In RCP6, high emission levels of SO_2 in China persist until the mid-21st century (Supplementary Material Figure 8.SM.1), and then it is predicted to keep a high negative RF due to aerosol–radiation interaction over East Asia. The RF due to aerosol–radiation interaction for carbonaceous aerosol is positive over East and South Asia in 2030 relative to 2000 for RCP8.5 because BC emission is also larger in 2030. Over central and southern Africa, a change in the future RF due to aerosol–radiation interaction based on RCPs is not clear mainly because of uncertainties in the wildfires emissions (see Section 7.3.5.3). The global mean total RF due to aerosol–radiation interaction in the future is rather small due to offsetting effects, with reductions in BC, increases in nitrate aerosols, and reductions in scattering aerosols each causing substantially more forcing than the net.

Emissions and atmospheric loadings of natural aerosols are affected by climate change. There is, however, no consensus among studies on future trends of their changes for major natural aerosols, mineral dust and sea salt, as indicated in Section 7.3.5.1. The spatial pattern of the aerosol forcing may be influenced by natural aerosols due to reduction in sea ice cover leading to increased emission of high-latitude sea salt (Struthers et al., 2011; Takemura, 2012) and SOA from vegetation changes (Tsigaridis and Kanakidou, 2007).

The simulations applying the RCPs indicate that the latitude of maximum emission of NTCFs, and therefore of maximum RF, is projected to shift somewhat southward for the next few decades (in 2030 of Figure 8.26). The shift of peak aerosol loading southward is expected to cause the ITCZ to continue to shift northward. This, in combination with warming and drying over tropical land, has been modelled to lead to greatly enhanced drought conditions in the Amazon (Cox et al., 2008). On the other hand, if the low-latitude aerosol is sufficiently absorbing, broadening of the ITCZ convergence region and enhanced cloud cover could result, as modelled for dust (Perlwitz and Miller, 2010).

Reductions in high-latitude BC are expected to contribute to reducing Arctic forcing (e.g., Koch et al., 2011), due to reduction in BC deposition on snow as well as in absorption of sunlight over bright surface. On the other hand, reduction in mid-high-latitude scattering aerosols may offset all or part of the impact of the local Arctic forcing change (Shindell et al., 2010; Koch et al., 2011).

Figure 8.26 also shows the ozone RF in 2030 and 2100 relative to 2000, which includes changes both in tropospheric and stratospheric ozone. Recovery of ozone in the stratosphere in the 21st century will result in positive forcing in the SH high latitudes in comparison with the year 2000 for both the pathways. This is because of the reduced emissions of ozone-depleting substances controlled under the Montreal Protocol, with a small additional effect from a feedback of changes in temperature and in the vertical circulation due to changes in stratospheric compositions (Kawase et al., 2011; Lamarque et al., 2011). In the troposphere, on the other hand, a large difference in the CH_4 emissions between RCP8.5 and the other pathways shown in Figure 8.2 leads to a different RF trend outside the SH high latitudes. Ozone recovery in the stratosphere and ozone increase in the troposphere leads to a positive RF all over the globe in RCP8.5 with a mean of +0.26 W m^{-2} in 2100. The cancellation between positive RF due to ozone increase in the stratosphere and negative RF due to ozone decrease in the troposphere results in a global mean RF of –0.12 W m^{-2} in RCP2.6.

Figure 8.26 also shows the global distributions of changes in ERF due to both aerosol–radiation and aerosol–cloud interactions in 2030 and 2100 relative to 2000 for RCP8.5. Although the ERF includes rapid adjustments and therefore its magnitude is much larger than that of RF due to aerosol–radiation interaction, the spatial pattern is generally similar to RF. The ERF in 2100 shows positive values relative to 2000 in North America, Europe and Asia even with RCP8.5, which indicates the aerosol forcing is projected to approach to the pre-industrial level.

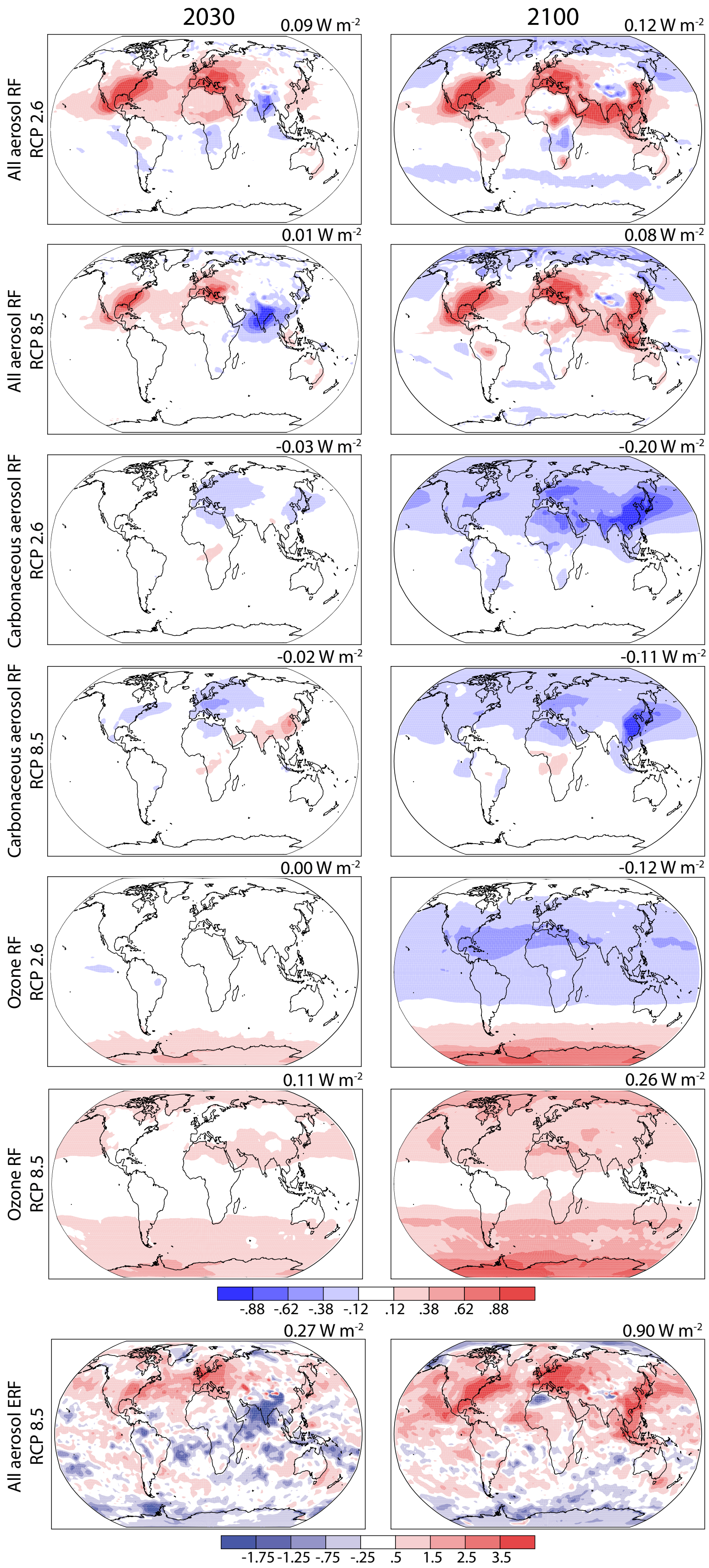


Figure 8.26 | Multi-model mean RF (W m^{-2}) due to aerosol–radiation interaction of all anthropogenic aerosols (first and second rows) and anthropogenic carbonaceous (BC+OC) aerosols (third and fourth rows), and total ozone (fifth and sixth rows) in 2030 (left) and 2100 (right) relative to 2000 for RCP2.6 (top each) and RCP8.5 (bottom each) based on the ACCMIP simulations. The seventh row shows multi-model mean ERF (W m^{-2}) by all anthropogenic aerosols in 2030 (left) and 2100 (right) relative to 2000 for RCP8.5. Global area-weighted means are given in the upper right of each panel.

8.7 Emission Metrics

8.7.1 Metric Concepts

8.7.1.1 Introduction

To quantify and compare the climate impacts of various emissions, it is necessary to choose a climate parameter by which to measure the effects; that is, RF, temperature response, and so forth. Thus, various choices are needed for the steps down the cause–effect chain from emissions to climate change and impacts (Figure 8.27 and Box 8.4). Each step in the cause effect chain requires a modelling framework. For assessments and evaluation one may—as an alternative to models that explicitly include physical processes resulting in forcing and responses—apply simpler measures or *metrics* that are based on results from complex models. Metrics are used to quantify the contributions to climate change of emissions of different substances and can thus act as 'exchange rates' in multi-component policies or comparisons of emissions from regions/countries or sources/sectors. Metrics are also used in areas such as Life Cycle Assessments and Integrated Assessment Modelling (e.g., by IPCC WGIII).

Metrics can be given in *absolute* terms (e.g., K kg^{-1}) or in *relative* terms by normalizing to a reference gas — usually CO_2. To transform the effects of different emissions to a common scale — often called 'CO_2 equivalent emissions'—the emission (E_i) of component *i* can be multiplied with the adopted normalized metric (M_i): $M_i \times E_i = CO_2\text{-eq}_i$. Ideally, the climate effects of the calculated CO_2 equivalent emissions should be the same regardless of the mix of components emitted. However, different components have different physical properties, and a metric that establishes equivalence with regard to one effect cannot guarantee equivalence with regard to other effects and over extended time periods, for example, Lauder et al. (2013), O'Neill (2000), Smith and Wigley (2000), Fuglestvedt et al. (2003).

Metrics do not define goals and policy—they are tools that enable evaluation and implementation of multi-component policies (i.e., which emissions to abate). The most appropriate metric will depend on which aspects of climate change are most important to a particular application, and different climate policy goals may lead to different conclusions about what is the most suitable metric with which to implement that policy, for example, Plattner et al. (2009); Tol et al. (2012). Metrics that have been proposed include physical metrics as well as more comprehensive metrics that account for both physical and economic dimensions (see 8.7.1.5 and WGIII, Chapter 3).

This section provides an assessment that focuses on the scientific aspects and utility of emission metrics. Extending such an assessment to include more policy-oriented aspects of their performance and usage such as simplicity, transparency, continuity, economic implications of usage of one metric over another, and so forth, is not given here as this is beyond the scope of WGI. However, consideration of such aspects is vital for user-assessments. In the following, the focus is on the more well-known Global Warming Potential (GWP) and Global Temperature change Potential (GTP), though other concepts are also briefly discussed.

8.7.1.2 The Global Warming Potential Concept

The Global Warming Potential (GWP) is defined as the time-integrated RF due to a pulse emission of a given component, relative to a pulse emission of an equal mass of CO_2 (Figure 8.28a and formula). The GWP was presented in the First IPCC Assessment (Houghton et al., 1990), stating 'It must be stressed that there is no universally accepted methodology for combining all the relevant factors into a single global warming potential for greenhouse gas emissions. A simple approach has been adopted here to illustrate the difficulties inherent in the concept, ...'. Further, the First IPCC Assessment gave no clear physical interpretation of the GWP.

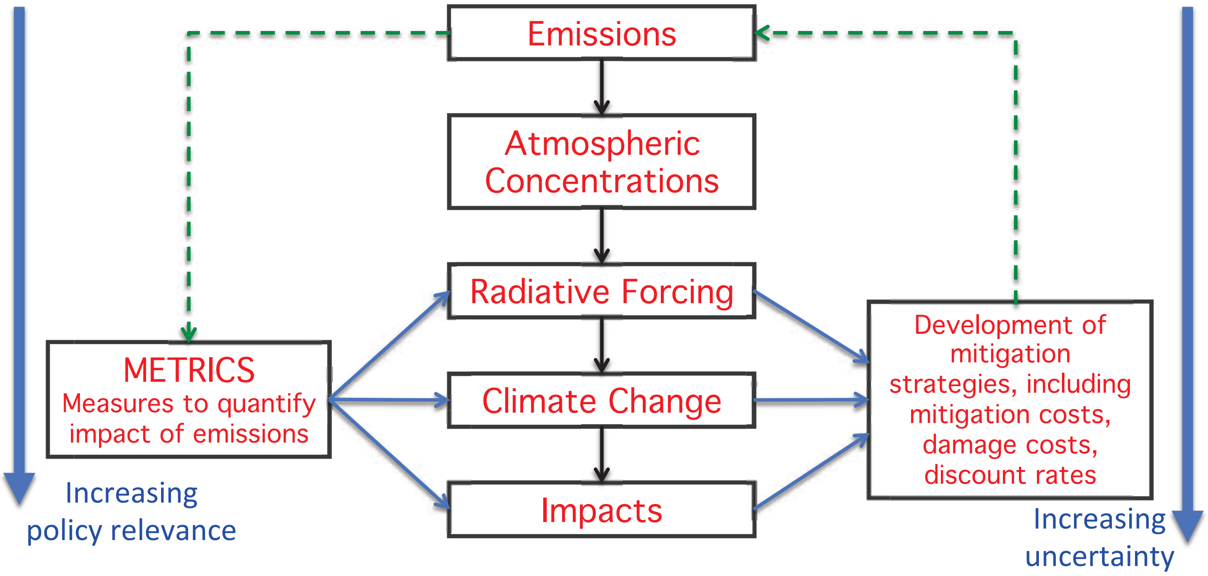


Figure 8.27 | The cause–effect chain from emissions to climate change and impacts showing how metrics can be defined to estimate responses to emissions (left) and for development of multi-component mitigation (right). The relevance of the various effects increases downwards but at the same time the uncertainty also increases. The dotted line on the left indicates that effects and impacts can be estimated directly from emissions, while the arrows on the right side indicate how these estimates can be used in development of strategies for reducing emissions. (Adapted from Fuglestvedt et al., 2003, and Plattner et al., 2009.)

Box 8.4 | Choices Required When Using Emission Metrics

Time frames: One can apply a *backward-looking* (i.e., historical) or a *forward-looking* perspective on the responses to emissions. In the forward-looking case one may use pulses of emissions, sustained emissions or emission scenarios. All choices of emission perturbations are somewhat artificial and idealized, and different choices serve different purposes. One may use the *level* (e.g., degrees Celsius) or *rate* of change (e.g., degrees Celsius per decade). Furthermore, the effects of emissions may be estimated at a particular time or be integrated over time up to a chosen time horizon. Alternatively, discounting of future effects may be introduced (i.e., a weighting of effects over time).

Type of effect or end-point: Radiative forcing, temperature change or sea level change, for example, could be examined (Figure 8.27). Metrics may also include eco/biological or socioeconomic damages. The choice of climate impact parameters is related to which aspects of climate change are considered relevant for interpretation of 'dangerous anthropogenic interference with the climate system' (UNFCCC Article 2).

Spatial dimension for emission and response: Equal-mass emissions of NTCFs from different regions can induce varying global mean climate responses, and the climate response also has a regional component irrespective of the regional variation in emissions. Thus, metrics may be given for region of *emission* as well as region of *response*.

Some of the choices involved in metrics are scientific (e.g., type of model, and how processes are included or parameterized in the models). Choices of time frames and climate impact are policy-related and cannot be based on science alone, but scientific studies can be used to analyse different approaches and policy choices.

A direct interpretation is that the GWP is an index of the total energy added to the climate system by a component in question relative to that added by CO_2. However, the GWP does not lead to equivalence with temperature or other climate variables (Fuglestvedt et al., 2000, 2003; O'Neill, 2000; Daniel et al., 2012; Smith and Wigley, 2000; Tanaka et al., 2009). Thus, the name 'Global Warming Potential' may be somewhat misleading, and 'relative cumulative forcing index' would be more appropriate. It can be shown that the GWP is approximately equal to the ratio (normalizing by the similar expression for CO_2) of the *equilibrium temperature response due to a sustained emission* of the species or to the *integrated temperature response for a pulse* emission (assuming efficacies are equal for the gases that are compared; O'Neill, 2000; Prather, 2002; Shine et al., 2005a; Peters et al., 2011a; Azar and Johansson, 2012).

The GWP has become the default metric for transferring emissions of different gases to a common scale; often called 'CO_2 equivalent emissions' (e.g., Shine, 2009). It has usually been integrated over 20, 100 or 500 years consistent with Houghton et al. (1990). Note, however that Houghton et al. presented these time horizons as 'candidates for discussion [that] should not be considered as having any special significance'. The GWP for a time horizon of 100 years was later adopted as a metric to implement the multi-gas approach embedded in the United Nations Framework Convention on Climate Change (UNFCCC) and made operational in the 1997 Kyoto Protocol. The choice of time horizon has a strong effect on the GWP values — and thus also on the calculated contributions of CO_2 equivalent emissions by component, sector or nation. There is no scientific argument for selecting 100 years compared with other choices (Fuglestvedt et al., 2003; Shine, 2009). The choice of time horizon is a value judgement because it depends

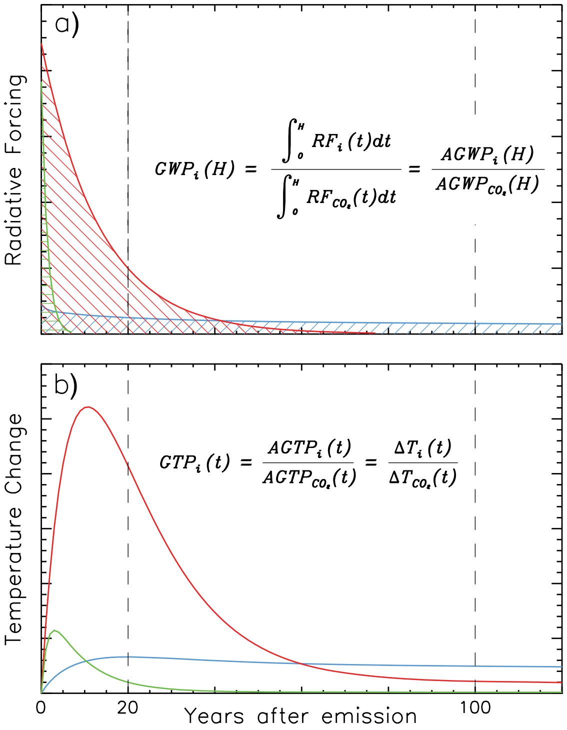


Figure 8.28 | (a) The Absolute Global Warming Potential (AGWP) is calculated by integrating the RF due to emission pulses over a chosen time horizon; for example, 20 and 100 years (vertical lines). The GWP is the ratio of AGWP for component *i* over AGWP for the reference gas CO_2. The blue hatched field represents the integrated RF from a pulse of CO_2, while the green and red fields represent example gases with 1.5 and 13 years lifetimes, respectively. (b) The Global Temperature change Potential (GTP) is based on the temperature response at a selected year after pulse emission of the same gases; e.g., 20 or 100 years (vertical lines). See Supplementary Material Section 8.SM.11 for equations for calculations of GWP and GTP.

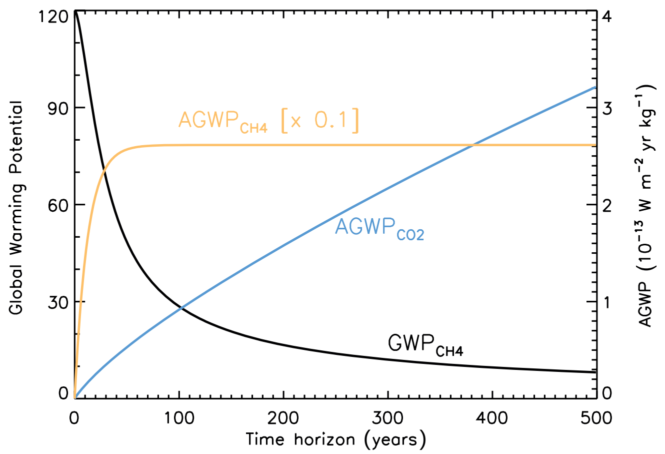


Figure 8.29 | Development of AGWP-CO_2, AGWP-CH_4 and GWP-CH_4 with time horizon. The yellow and blue curves show how the AGWPs changes with increasing time horizon. Because of the integrative nature the AGWP for CH_4 (yellow curve) reaches a constant level after about five decades. The AGWP for CO_2 continues to increase for centuries. Thus the ratio which is the GWP (black curve) falls with increasing time horizon.

on the relative weight assigned to effects at different times. Other important choices include the background atmosphere on which the GWP calculations are superimposed, and the way indirect effects and feedbacks are included (see Section 8.7.1.4).

For some gases the variation in GWP with time horizon mainly reflects properties of the reference gas, not the gas for which the GWP is calculated. The GWP for NTCFs decreases with increasing time horizon, as GWP is defined with the integrated RF of CO_2 in the denominator. As shown in Figure 8.29, after about five decades the development in the GWP for CH_4 is almost entirely determined by CO_2. However, for long-lived gases (e.g., SF_6) the development in GWP is controlled by both the increasing integrals of RF from the long-lived gas and CO_2.

8.7.1.3 The Global Temperature change Potential Concept

Compared to the GWP, the Global Temperature change Potential (GTP; Shine et al., 2005a) goes one step further down the cause–effect chain (Figure 8.27) and is defined as the *change in global mean surface temperature at a chosen point in time* in response to an emission pulse—relative to that of CO_2. Whereas GWP is integrated in time (Figure 8.28a), GTP is an end-point metric that is based on temperature change for a selected year, *t*, (see Figure 8.28b with formula). Like for the GWP, the impact from CO_2 is normally used as reference, hence, for a component *i*, $GTP(t)_i = AGTP(t)_i / AGTP(t)_{CO2} = \Delta T((t))_i / \Delta T(t)_{CO2}$, where AGTP is the absolute GTP giving temperature change per unit emission (see Supplementary Material Section 8.SM.11 for equations and parameter values). Shine et al. (2005a) presented the GTP for both pulse and sustained emission changes based on an energy balance model as well as analytical equations. A modification was later introduced (Shine et al., 2007) in which the time horizon is determined by the proximity to a target year as calculated by using scenarios and climate models (see Section 8.7.1.5).

Like GWP, the GTP values can be used for weighting the emissions to obtain 'CO_2 equivalents' (see Section 8.7.1.1). This gives the temperature effects of emissions relative to that of CO_2 for the chosen time horizon. As for GWP, the choice of time horizon has a strong effect on the metric values and the calculated contributions to warming.

In addition, the AGTP can be used to calculate the global mean temperature change due to any given emission scenario (assuming linearity) using a convolution of the emission scenarios and $AGTP_i$:

$$\Delta T(t) = \sum_i \int_0^t E_i(s) AGTP_i(t-s) ds \qquad (8.1)$$

where *i* is component, *t* is time, and *s* is time of emission (Berntsen and Fuglestvedt, 2008; Peters et al., 2011b; Shindell et al., 2011).

By accounting for the climate sensitivity and the exchange of heat between the atmosphere and the ocean, the GTP includes physical processes that the GWP does not. The GTP accounts for the slow response of the (deep) ocean, thereby prolonging the response to emissions beyond what is controlled by the decay time of the atmospheric concentration. Thus the GTP includes both the atmospheric adjustment time scale of the component considered and the response time scale of the climate system.

The GWP and GTP are fundamentally different by construction and different numerical values can be expected. In particular, the GWPs for NTCFs, over the same time frames, are higher than GTPs due to the integrative nature of the metric. The GTP values can be significantly affected by assumptions about the climate sensitivity and heat uptake by the ocean. Thus, the relative uncertainty ranges are wider for the GTP compared to GWP (see Section 8.7.1.4). The additional uncertainty is a typical trade-off when moving along the cause–effect chain to an effect of greater societal relevance (Figure 8.27). The formulation of the ocean response in the GTP has a substantial effect on the values; thus its characterization also represents a trade-off between simplicity and accuracy. As for GWP, the GTP is also influenced by the background atmosphere, and the way indirect effects and feedbacks are included (see Section 8.7.1.4).

8.7.1.4 Uncertainties and Limitations related to Global Warming Potential and Global Temperature change Potential

The uncertainty in the numerator of GWP; that is, the $AGWP_i$ (see formula in Figure 8.28a) is determined by uncertainties in lifetimes (or perturbation lifetimes) and radiative efficiency. Inclusion of indirect effects increases uncertainties (see below). For the reference gas CO_2, the uncertainty is dominated by uncertainties in the *impulse response function* (IRF) that describes the development in atmospheric concentration that follows from an emission pulse (Joos et al., 2013); see Box 6.2 and Supplementary Material Section 8.SM.12. The IRF is sensitive to model representation of the carbon cycle, pulse size and background CO_2 concentrations and climate.

Based on a multi-model study, Joos et al. (2013) estimate uncertainty ranges for the time-integrated IRF for CO_2 to be ±15% and ±25% (5 to 95% uncertainty range) for 20- and 100-year time horizons, respectively. Assuming quadratic error propagation, and ±10% uncertainty in radiative efficiency, the uncertainty ranges in AGWP for CO_2 were estimated to be ±18% and ±26% for 20 and 100 years. These uncertainties affect all metrics that use CO_2 as reference. Reisinger et al. (2010) and Joos et al. (2013) show that these uncertainties increase with time horizon.

The same factors contribute to uncertainties in the GTP, with an additional contribution from the parameters describing the ocean heat uptake and climate sensitivity. In the first presentation of the GTP, Shine et al. (2005a) used one time constant for the climate response in their analytical expression. Improved approaches were used by Boucher and Reddy (2008), Collins et al. (2010) and Berntsen and Fuglestvedt (2008) that include more explicit representations of the deep ocean that increased the long-term response to a pulse forcing. Over the range of climate sensitivities from AR4, GTP_{50} for BC was found to vary by a factor of 2, the CH_4 GTP_{50} varied by about 50%, while for N_2O essentially no dependence was found (Fuglestvedt et al., 2010). AGTPs for CO_2 were also calculated in the multi-model study by Joos et al. (2013). They found uncertainty ranges in AGTP that are much larger than for AGWP; ±45% and ±90% for 20 and 100 years (5 to 95% uncertainty range). These uncertainty ranges also reflect the signal-to-noise ratio, and not only uncertainty in the physical mechanisms.

There are studies combining uncertainties in various input parameters. Reisinger et al. (2011) estimated the uncertainty in the GWP for CH_4 and found an uncertainty of –30 to +40% for the GWP_{100} and –50 to +75% for GTP_{100} of CH_4 (for 5 to 95% of the range). Boucher (2012) performed a Monte Carlo analysis with uncertainties in perturbation lifetime and radiative efficiency, and for GWP_{100} for CH_4 (assuming a constant background atmosphere) he found ±20%, and –40 to +65 for GTP_{100} (for 5 to 95% uncertainty range).

Here we estimate uncertainties in GWP values based on the uncertainties given for radiative efficiencies (Section 8.3.1), perturbation lifetimes, indirect effects and in the AGWP for the reference gas CO_2 (see Supplementary Material Section 8.SM.12). For CH_4 GWP we estimate an uncertainty of ±30% and ±40% for 20- and 100-year time horizons, respectively (for 5 to 95% uncertainty range). The uncertainty is dominated by AGWP for CO_2 and indirect effects. For gases with lifetimes of a century or more the uncertainties are of the order of ±20% and ±30% for 20- and 100-year horizons. The uncertainty in GWPs for gases with lifetimes of a few decades is estimated to be of the order of ±25% and ±35% for 20 and 100 years. For shorter-lived gases, the uncertainties in GWPs will be larger (see Supplementary Material Section 8.SM.12 for a discussion of contributions to the total uncertainty.) For GTP, few uncertainty estimates are available in the literature. Based on the results from Joos et al. (2013), Reisinger et al. (2010) and Boucher (2012) we assess the uncertainty to be of the order of ±75% for the CH_4 GTP_{100}.

The metric values are also strongly dependent on which processes are included in the definition of a metric. Ideally all indirect effects (Sections 8.2 and 8.3) should be taken into account in the calculation of metrics. The indirect effects of CH_4 on its own lifetime, tropospheric ozone and stratospheric water have been traditionally included in its GWP. Boucher et al. (2009) have quantified an indirect effect on CO_2 when fossil fuel CH_4 is oxidized in the atmosphere. Shindell et al. (2009) estimated the impact of reactive species emissions on both gaseous and aerosol forcing species and found that ozone precursors, including CH_4, had an additional substantial climate effect because they increased or decreased the rate of oxidation of SO_2 to sulphate aerosol. Studies with different sulphur cycle formulations have found lower sensitivity (Collins et al., 2010; Fry et al., 2012). Collins et al. (2010) postulated an additional component to their GWPs and GTPs for ozone precursors due to the decreased productivity of plants under higher levels of surface ozone. This was estimated to have the same magnitude as the ozone and CH_4 effects. This effect, however, has so far only been examined with one model. In a complex and interconnected system, feedbacks can become increasingly complex, and uncertainty of the magnitude and even direction of feedback increases the further one departs from the primary perturbation, resulting in a trade-off between completeness and robustness, and hence utility for decision-making.

Gillett and Matthews (2010) included climate–carbon feedbacks in calculations of GWP for CH_4 and N_2O and found that this increased the values by about 20% for 100 years. For GTP of CH_4 they found an increase of ~80%. They used numerical models for their studies and suggest that climate–carbon feedbacks should be considered and parameterized when used in simple models to derive metrics. Collins et al. (2013) parameterize the climate-carbon feedback based on Friedlingstein et al. (2006) and Arora et al. (2013) and find that this more than doubles the GTP_{100} for CH_4. Enhancement of the GTP for CH_4 due to carbon–climate feedbacks may also explain the higher GTP values found by Reisinger et al. (2010).

The inclusion of indirect effects and feedbacks in metric values has been inconsistent in the IPCC reports. In SAR and TAR, a carbon model without a coupling to a climate model was used for calculation of IRF for CO_2 (Joos et al., 1996), while in AR4 climate-carbon feedbacks were included for the CO_2 IRF (Plattner et al., 2008). For the time horizons 20 and 100 years, the $AGWP_{CO2}$ calculated with the Bern3D-LPJ model is, depending on the pulse size, 4 to 5% and 13 to 15% lower, respectively, when carbon cycle–climate feedbacks are not included (Joos et al., 2013). While the AGWP for the reference gas CO_2 included climate–carbon feedbacks, this is not the case for the non-CO_2 gas in the numerator of GWP, as recognized by Gillett and Matthews (2010), Joos et al. (2013), Collins et al. (2013) and Sarofim (2012). This means that the GWPs presented in AR4 may underestimate the relative impacts of non-CO_2 gases. The different inclusions of feedbacks partially represent the current state of knowledge, but also reflect inconsistent and ambiguous definitions. In calculations of AGWP for CO_2 in AR5 we use the IRF for CO_2 from Joos et al. (2013) which includes climate–carbon feedbacks. Metric values in AR5 are presented both with and without including climate–carbon feedbacks for non-CO_2 gases. This feedback is based on the carbon-cycle response in a similar set of models (Arora et al., 2013) as used for the reference gas (Collins et al., 2013).

The effect of including this feedback for the non-reference gas increases with time horizon due to the long-lived nature of the initiated CO_2 perturbation (Table 8.7). The relative importance also increases with decreasing lifetime of the component, and is larger for GTP than GWP due to the integrative nature of GWP. We calculate an increase in the CH_4 GWP_{100} of 20%. For GTP_{100}, however, the changes are much larger; of the order of 160%. For the shorter time horizons (e.g., 20 years) the effect of including this feedback is small (<5%) for both GWP

Table 8.7 | GWP and GTP with and without inclusion of climate–carbon feedbacks (cc fb) in response to emissions of the indicated non-CO_2 gases (climate-carbon feedbacks in response to the reference gas CO_2 are always included).

	Lifetime (years)		GWP_{20}	GWP_{100}	GTP_{20}	GTP_{100}
CH_4[b]	12.4[a]	No cc fb	84	28	67	4
		With cc fb	86	34	70	11
HFC-134a	13.4	No cc fb	3710	1300	3050	201
		With cc fb	3790	1550	3170	530
CFC-11	45.0	No cc fb	6900	4660	6890	2340
		With cc fb	7020	5350	7080	3490
N_2O	121.0[a]	No cc fb	264	265	277	234
		With cc fb	268	298	284	297
CF_4	50,000.0	No cc fb	4880	6630	5270	8040
		With cc fb	4950	7350	5400	9560

Notes:

Uncertainties related to the climate–carbon feedback are large, comparable in magnitude to the strength of the feedback for a single gas.

[a] Perturbation lifetime is used in the calculation of metrics.

[b] These values do not include CO_2 from methane oxidation. Values for fossil methane are higher by 1 and 2 for the 20 and 100 year metrics, respectively (Table 8.A.1).

and GTP. For the more long-lived gases the GWP_{100} values increase by 10 to 12%, while for GTP_{100} the increase is 20 to 30%. Table 8.A.1 gives metric values including the climate–carbon feedback for CO_2 only, while Supplementary Material Table 8.SM.16 gives values for all halocarbons that include the climate–carbon feedback. Though uncertainties in the carbon cycle are substantial, it is *likely* that including the climate–carbon feedback for non-CO_2 gases as well as for CO_2 provides a better estimate of the metric value than including it only for CO_2.

Emission metrics can be estimated based on a constant or variable background climate and this influences both the adjustment times and the concentration–forcing–temperature relationships. Thus, all metric values will need updating due to changing atmospheric conditions as well as improved input data. In AR5 we define the metric values with respect to a constant present-day condition of concentrations and climate. However, under non-constant background, Joos et al. (2013) found decreasing CO_2 $AGWP_{100}$ for increasing background levels (up to 23% for RCP8.5). This means that GWP for all non-CO_2 gases (except CH_4 and N_2O) would increase by roughly the same magnitude. Reisinger et al. (2011) found a reduction in AGWP for CO_2 of 36% for RCP8.5 from 2000 to 2100 and that the CH_4 radiative efficiency and AGWP also decrease with increasing CH_4 concentration. Accounting for both effects, the GWP_{100} for CH_4 would increase by 10 to 20% under low and mid-range RCPs by 2100, but would decrease by up to 10% by mid-century under the highest RCP. While these studies have focused on the background levels of GHGs, the same issues apply for temperature. Olivié et al. (2012) find different temperature IRFs depending on the background climate (and experimental set up).

User related choices (see Box 8.4) such as the time horizon can greatly affect the numerical values obtained for CO_2 equivalents. For a change in time horizon from 20 to 100 years, the GWP for CH_4 decreases by a factor of approximately 3 and its GTP by more than a factor of 10. Short-lived species are most sensitive to this choice. Some approaches have removed the time horizon from the metrics (e.g., Boucher, 2012), but discounting is usually introduced which means that a discount rate r (for the weighting function e^{-rt}) must be chosen instead. The choice of discount rate is also value based (see WGIII, Chapter 3).

For NTCFs the metric values also depend on the location and timing of emission and whether regional or global metrics are used for these gases is also a choice for the users. Metrics are usually calculated for pulses, but some studies also give metric values that assume constant emissions over the full time horizon (e.g., Shine et al., 2005a; Jacobson, 2010). It is important to be aware of the idealized assumption about constant future emissions (or change in emissions) of the compound being considered if metrics for sustained emissions are used.

8.7.1.5 New Metric Concepts

New metric concepts have been developed both to modify physical metrics to address shortcomings as well as to replace them with metrics that account for economic dimensions of problems to which metrics are applied. Modifications to physical metrics have been proposed to better represent CO_2 emissions from bioenergy, regional patterns of response, and for peak temperature limits.

Emissions of CO_2 from the combustion of biomass for energy in national emission inventories are currently assumed to have no net RF, based on the assumption that these emissions are compensated by biomass regrowth (IPCC, 1996). However, there is a time lag between combustion and regrowth, and while the CO_2 is resident in the atmosphere it leads to an additional RF. Modifications of the GWP and GTP for bioenergy (GWP_{bio}, GTP_{bio}) have been developed (Cherubini et al., 2011; Cherubini et al., 2012). The GWP_{bio} give values generally between zero (current default for bioenergy) and one (current for fossil fuel emissions) (Cherubini et al., 2011), and negative values are possible for GTP_{bio} due to the fast time scale of atmospheric–ocean CO_2 exchange relative to the growth cycle of biomass (Cherubini et al., 2012). GWP_{bio} and GTP_{bio} have been used in only a few applications, and more research is needed to assess their robustness and applicability. Metrics for biogeophysical effects, such as albedo changes, have been proposed (Betts, 2000; Rotenberg and Yakir, 2010) , but as for NTCFs regional variations are important (Claussen et al., 2001) and the RF concept may not be adequate (Davin et al., 2007).

New concepts have also been developed to capture information about regional patterns of responses and cancelling effects that are lost when global mean metrics are used. The use of nonlinear damage functions to capture information on the spatial pattern of responses has been explored (Shine et al., 2005b; Lund et al., 2012). In addition, the Absolute Regional Temperature Potential (ARTP) (Shindell, 2012; Collins et al., 2013) has been developed to provide estimates of impacts at a sub-global scale. ARTP gives the time-dependent temperature response in four latitude bands as a function of the regional forcing imposed in all bands. These metrics, as well as new regional precipitation metrics (Shindell et al., 2012b), require additional studies to determine their robustness.

Alternatives to the single basket approach adopted by the Kyoto Protocol are a component-by-component approach or a multi-basket approach (Rypdal et al., 2005; Daniel et al., 2012; Sarofim, 2012; Jackson, 2009). Smith et al. (2012) show how peak temperature change is constrained by *cumulative emissions* (see 12.5.4) for gases with long lifetimes and *emissions rates* for shorter-lived gases (including CH_4). Thus, they divide gases into two baskets and present two metrics that can be used for estimating peak temperature for various emission scenarios. This division of gases into the two baskets is sensitive to the time of peak temperature in the different scenarios. The approach uses time invariant metrics that do not account for the timing of emissions relative to the target year. The choice of time horizon is implicit in the scenario assumed and this approach works only for a peak scenario.

A number of new metrics have been developed to add economic dimensions to purely physically based metrics such as the GWP and GTP. The use of physical metrics in policy contexts has been criticized by economists (Reilly and Richards, 1993; Schmalensee, 1993; Hammitt et al., 1996; Reilly et al., 1999; Bradford, 2001; De Cara et al., 2008). A prominent use of metrics is to set relative prices of gases when implementing a multi-gas policy. Once a particular policy has been agreed on, economic metrics can address policy goals more directly than physical metrics by accounting not only for physical dimensions but also for economic dimensions such as mitigation costs, damage costs and discount rates (see WGIII, Chapter 3; Deuber et al., 2013).

For example, if mitigation policy is set within a *cost-effectiveness* framework with the aim of making the least cost mix of emissions reductions across components to meet a global temperature target, the 'price ratio' (Manne and Richels, 2001), also called the Global Cost Potential (GCP) (Tol et al., 2012), most directly addresses the goal. The choice of target is a policy decision; metric values can then be calculated based on an agreed upon target. Similarly, if policy is set within a *cost–benefit* framework, the metric that directly addresses the policy goal is the ratio of the marginal damages from the emission of a gas (i.e., the damage costs to society resulting from an incremental increase in emissions) relative to the marginal damages of an emission of CO_2, known as the Global Damage Potential (GDP) (Kandlikar, 1995). Both types of metrics are typically determined within an integrated climate–economy model, since they are affected both by the response of the climate system as well as by economic factors.

If other indexes, such as the GWP, are used instead of an economic cost-minimizing index, costs to society will increase. Cost implications at the project or country level could be substantial under some circumstances (Godal and Fuglestvedt, 2002; Shine, 2009; Reisinger et al., 2013). However, under idealized conditions of full participation in mitigation policy, the increase is relatively small at the global level, particularly when compared to the cost savings resulting from a multi- (as opposed to single-) gas mitigation strategy even when based on an imperfect metric (O'Neill, 2003; Aaheim et al., 2006; Johansson et al., 2006; Johansson, 2012; Reisinger et al., 2013; Smith et al., 2013).

Purely physical metrics continue to be used in many contexts due at least in part to the added uncertainties in mitigation and damage costs, and therefore in the values of economic metrics (Boucher, 2012). Efforts have been made to view purely physical metrics such as GWPs and GTPs as approximations of economic indexes. GTPs, for example, can be interpreted as an approximation of a Global Cost Potential designed for use in a cost-effectiveness setting (Shine et al., 2007; Tol et al., 2012). Quantitative values for time-dependent GTPs reproduce in broad terms several features of the Global Cost Potential such as the rising value of metrics for short-lived gases as a climate policy target is approached (Tanaka et al., 2013). Figure 8.30 shows how contributions of N_2O, CH_4 and BC to warming in the target year changes over time. The contributions are given relative to CO_2 and show the effects of emission occurring at various times. Similarly, GWPs can be interpreted as approximations of the Global Damage Potential designed for a cost–benefit framework (Tol et al., 2012). These interpretations of the GTP and GWP imply that using even a purely physical metric in an economic policy context involves an implicit economic valuation.

In both cases, a number of simplifying assumptions must be made for these approximations to hold (Tol et al., 2012). For example, in the case of the GWP, the influence of emissions on RF, and therefore implicitly on costs to society, beyond the time horizon is not taken into account, and there are substantial numerical differences between GWP and GDP values (Marten and Newbold, 2012). In the case of the GTP, the influence of emissions on temperature change (and costs) is

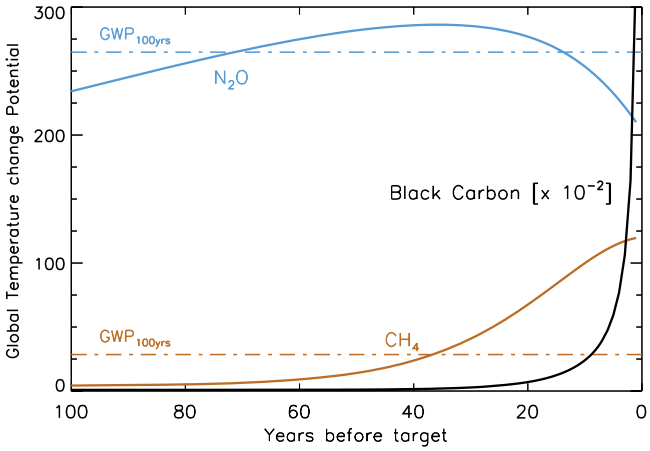


Figure 8.30 | Global Temperature change Potential (GTP(*t*)) for CH_4, nitrous oxide and BC for each year from year of emission to the time at which the temperature change target is reached. The (time-invariant) GWP_{100} is also shown for N_2O and CH_4 for comparison.

included only at the time the target is reached, but not before nor after. Other metrics have been developed to more closely approximate GCPs or GDPs. The Cost-Effective Temperature Potential (CETP) reproduces values of the GCP more closely than does the GTP (Johansson, 2012). It is similar to the GTP but accounts for post-target temperature effects based on an assumption about how to value costs beyond the time the target is reached. Metrics have also been proposed that take into account forcing or temperature effects that result from emissions trajectories over broad time spans, and that behave similarly to GCP and GTP (Tanaka et al., 2009; Manning and Reisinger, 2011) or to GWP (e.g., O'Neill, 2000; Peters et al., 2011a; Gillett and Matthews, 2010; Azar and Johansson, 2012).

8.7.1.6 Synthesis

In the application and evaluation of metrics, it is important to distinguish between two main sources of variation in metric values. While scientific choices of input data have to be made, there are also choices involving value judgements. For some metrics such choices are not always explicit and transparent. The choice of metric type and time horizon will for many components have a much larger effect than improved estimates of input parameters and can have strong effects on perceived impacts of emissions and abatement strategies.

In addition to progress in understanding of GWP, new concepts have been introduced or further explored since AR4. Time variant metrics introduce more dynamical views of the temporal contributions that accounts for the proximity to a prescribed target (in contrast to the traditional static GWP). Time variant metrics can be presented in a format that makes changing metric values over time predictable.

As metrics use parameters further down the cause effect chain the metrics become in general more policy relevant, but at the same time the uncertainties increase. Furthermore, metrics that account for regional variations in sensitivity to emissions or regional variation in response could give a very different emphasis to various emissions. Many species, especially NTCFs, produce distinctly regionally heterogeneous RF and climate response patterns. These aspects are not accounted for in the commonly used global scale metrics.

The GWPs and GTPs have had inconsistent treatment of indirect effects and feedbacks. The GWPs reported in AR4 include climate–carbon feedbacks for the reference gas CO_2 but not for the non-CO_2 gases. Such feedbacks may have significant impacts on metrics and should be treated consistently. More studies are needed to assess the importance of consistent treatment of indirect effects/feedbacks in metrics.

The weighting of effects over time—choice of time horizon in the case of GWP and GTP—is value based. Discounting is an alternative, which also includes value judgements and is equally controversial. The weighting used in the GWP is a weight equal to one up to the time horizon and zero thereafter, which is not in line with common approaches for evaluation of future effects in economics (e.g., as in WGIII, Chapter 3). Adoption of a fixed horizon of e.g., 20, 100 or 500 years will inevitably put no weight on the long-term effect of CO_2 beyond the time horizon (Figure 8.28 and Box 6.1). While GWP integrates the effects up to a chosen time horizon the GTP gives the temperature just for one chosen year with no weight on years before or after. The most appropriate metric depends on the particular application and which aspect of climate change is considered relevant in a given context. The GWP is not directly related to a temperature limit such as the 2°C target (Manne and Richels, 2001; Shine et al., 2007; Manning and Reisinger, 2011; Smith et al., 2012; Tol et al., 2012; Tanaka et al., 2013), whereas some economic metrics and physical end-point metrics like the GTP may be more suitable for this purpose.

To provide metrics that can be useful to the users and policymakers a more effective dialog and discussion on three topics is needed: (1) which applications particular metrics are meant to serve; (2) how comprehensive metrics need to be in terms of indirect effects and feedbacks, and economic dimensions; and—related to this (3) how important it is to have simple and transparent metrics (given by analytical formulations) versus more complex model-based and thus model-dependent metrics. These issues are also important to consider in a wider disciplinary context (e.g., across the IPCC Working Groups). Finally, it is important to be aware that all metric choices, even 'traditional' or 'widely used' metrics, contain implicit value judgements as well as large uncertainties.

8.7.2 Application of Metrics

8.7.2.1 Metrics for Carbon Dioxide, Methane, Nitrous Oxide, Halocarbons and Related Compounds

Updated (A)GWP and (A)GTP values for CO_2, CH_4, N_2O, CFCs, HCFCs, bromofluorocarbons, halons, HFCs, PFCs, SF_6, NF_3, and related halogen-containing compounds are given for some illustrative and tentative time horizons in Tables 8.7, 8.A.1 and Supplementary Material Table 8.SM.16. The input data and methods for calculations of GWPs and GTPs are documented in the Supplementary Material Section 8.SM.13. Indirect GWPs that account for the RF caused by depletion of stratospheric ozone (consistent with Section 8.3.3) are given for selected gases in Table 8.A.2.

The *confidence* in the ability to provide useful metrics at time scales of several centuries is *very low* due to nonlinear effects, large uncertainties for multi-century processes and strong assumptions of constant background conditions. Thus, we do not give metric values for longer time scales than 100 years (see discussion in Supplementary Material Section 8.SM.11). However, these time scales are important to consider for gases such as CO_2, SF_6 and PFCs. For CO_2, as much as 20 to 40% of the initial increase in concentration remains after 500 years. For PFC-14, 99% of an emission is still in the atmosphere after 500 years. The effects of emissions on these time scales are discussed in Chapter 12.

The GWP values have changed from previous assessments due to new estimates of lifetimes, impulse response functions and radiative efficiencies. These are updated due to improved knowledge and/or changed background levels. Because CO_2 is used as reference, any changes for this gas will affect all metric values via AGWP changes. Figure 8.31 shows how the values of radiative efficiency (RE), integrated impulse response function (IRF) and consequentially AGWP for CO_2 have changed from earlier assessments relative to AR5 values. The net effect of change in RE and IRF is an increase of approximately 1% and

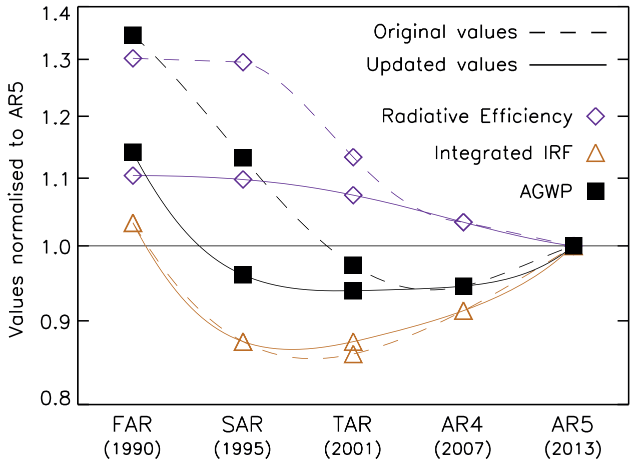


Figure 8.31 | Changes in the radiative efficiency (RE), integrated impulse response function (IRF) and Absolute Global Warming Potential (AGWP) for CO_2 for 100 years from earlier IPCC Assessment Reports normalized relative to the values given in AR5. The 'original' values are calculated based on the methods explained or value reported in each IPCC Assessment Report. The 'updated' values are calculated based on the methods used in AR5, but the input values from each Assessment Report. The difference is primarily in the formula for the RE, which was updated in TAR. The different integrated IRF in TAR relates to a different parameterisation of the same IRF (WMO, 1999). Changes represent both changes in scientific understanding and a changing background atmospheric CO_2 concentration (note that *y*-axis starts from 0.8). The lines connecting individual points are meant as a visual guide and not to represent the values between different Assessment Reports.

6% from AR4 to AR5 in AGWP for CO_2 for 20 and 100 years, respectively (see Supplementary Material Section 8.SM.12). These increases in the AGWP of the reference gas lead to corresponding decreases in the GWPs for all non-CO_2 gases. Continued increases in the atmospheric levels of CO_2 will lead to further changes in GWPs (and GTPs) in the future.

To understand the factors contributing to changes relative to AR4, comparisons are made here using the AR5 values that include climate–carbon feedbacks for CO_2 only. Relative to AR4 the CH_4 AGWP has changed due to changes in perturbation lifetime, a minor change in RE due to an increase in background concentration, and changes in the estimates of indirect effects. The indirect effects on O_3 and stratospheric H_2O are accounted for by increasing the effect of CH_4 by 50% and 15%, respectively (see Supplementary Material Table 8.SM.12). The ozone effect has doubled since AR4 taking into account more recent studies as detailed in Sections 8.3.3 and 8.5.1. Together with the changes in AGWP for CO_2 the net effect is increased GWP values of CH_4.

The GWPs for N_2O are lower here compared to AR4. A longer perturbation lifetime is used in AR5, while the radiative efficiency is lower due to increased abundances of CH_4 and N_2O. In addition, the reduction in CH_4 via stratospheric O_3, UV fluxes and OH levels due to increased N_2O abundance is included in GWPs and GTP. Owing to large uncertainties related to altitude of changes, we do not include the RF from stratospheric ozone changes as an indirect effect of N_2O.

Lifetimes for most of the halocarbons are taken from WMO (2011) and many of these have changed from AR4. The lifetimes of CFC-114, CFC-115 and HCF-161 are reduced by approximately 40%, while HFC-152 is reduced by one third. Among the hydrofluoroethers (HFEs) there are also several large changes in lifetimes. In addition, substantial updates of radiative efficiencies are made for several important gases; CFC-11, CFC-115, HCFC-124, HCFC-225cb, HFC-143a, HFC-245fa, CCl_4, $CHCl_3$, and SF_6. The radiative efficiency for carbon tetrachloride (CCl_4) is higher now and the GWP_{100} has increased by almost 25% from AR4. Uncertainties in metric values are given in Section 8.7.1.4. See also Supplementary Material Section 8.SM.12 and footnote to Table 8.A.1. As can be seen from Table 8.A.2, some ODS have strong indirect effects through stratospheric ozone forcing, which for some of the gases reduce their net GWP_{100} values substantially (and for the halons, to large negative values). Note that, consistent with Section 8.3.3, the uncertainties are large; ±100% for this indirect effect.

When climate-carbon feedbacks are included for both the non-CO_2 and reference gases, all metric values increase relative to the methodology used in AR4, sometimes greatly (Table 8.7, Supplementary Material Table 8.SM.16). Though the uncertainties range for these metric values is greater, as uncertainties in climate-carbon feedbacks are substantial, these calculations provide a more consistent methodology.

8.7.2.2 Metrics for Near-Term Climate Forcers

The GWP concept was initially used for the WMGHGs, but later for NTCFs as well. There are, however, substantial challenges related to calculations of GWP (and GTP) values for these components, which is reflected in the large ranges of values in the literature. Below we present and assess the current status of knowledge and quantification of metrics for various NTCFs.

8.7.2.2.1 Nitrogen oxides

Metric values for NO_X usually include the short-lived ozone effect, CH_4 changes and the CH_4-controlled O_3 response. NO_X also causes RF through nitrate formation, and via CH_4 it affects stratospheric H_2O and through ozone it influences CO_2. In addition, NO_x affects CO_2 through nitrogen deposition (fertilization effect). Due to high reactivity and the many nonlinear chemical interactions operating on different time scales, as well as heterogeneous emission patterns, calculation of *net* climate effects of NO_X is difficult. The net effect is a balance of large opposing effects with very different temporal behaviours. There is also a large spread in values among the regions due to variations in chemical and physical characteristics of the atmosphere.

As shown in Table 8.A.3 the GTP and GWP values are very different. This is due to the fundamentally different nature of these two metrics (see Figure 8.28) and the way they capture the temporal behaviour of responses to NO_x emissions. Time variation of GTP for NO_X is complex, which is not directly seen by the somewhat arbitrary choices of time horizon, and the net GTP is a fine balance between the contributing terms. The general pattern for NO_X is that the short-lived ozone forcing is always positive, while the CH_4-induced ozone forcing and CH_4 forcing are always negative (see Section 8.5.1). Nitrate aerosols from NO_x emission are not included in Table 8.A.3. For the GTP, all estimates for NO_X from surface sources give a negative net effect. As discussed in Section 8.7.1.4 Collins et al. (2010) and Shindell et al. (2009) implemented further indirect effects, but these are not included in Table

8.A.3 due to large uncertainties. The metric estimates for NO_X reflect the level of knowledge, but they also depend on experimental design, treatment of transport processes, and modelling of background levels. The multi-model study by Fry et al. (2012) shows the gaseous chemistry response to NO_X is relatively robust for European emissions, but that the uncertainty is so large that for some regions of emissions it is not possible to conclude whether NO_X causes cooling or warming.

8.7.2.2.2 Carbon monoxide and volatile organic compounds

Emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) lead to production of ozone on short time scales. By affecting OH and thereby the levels of CH_4 they also initiate a positive long-term ozone effect. With its lifetime of 2 to 3 months, the effect of CO emissions is less dependent on location than is the case for NO_X (see Table 8.A.4). There is also less variation across models. However, Collins et al. (2010) found that inclusion of vegetation effects of O_3 increased the GTP values for CO by 20 to 50%. By including aerosol responses Shindell et al. (2009) found an increase in GWP_{100} by a factor of ~2.5. CO of fossil origin will also have a forcing effect by contributing to CO_2 levels. This effect adds 1.4 to 1.6 to the GWP_{100} for CO (Daniel and Solomon, 1998; Derwent et al., 2001). (The vegetation and aerosol effects are not included in the numbers in Table 8.A.4.)

VOC is not a well-defined group of hydrocarbons. This group of gases with different lifetimes is treated differently across models by lumping or using representative key species. However, the spread in metric values in Table 8.A.5 is moderate across regions, with highest values for emissions in South Asia (of the four regions studied). The effects via ozone and CH_4 cause warming, and the additional effects via interactions with aerosols and via the O_3–CO_2 link increase the warming effect further. Thus, the net effects of CO and VOC are less uncertain than for NO_X for which the net is a residual between larger terms of opposite sign. However, the formation of SOAs is usually not included in metric calculations for VOC, which introduces a cooling effect and increased uncertainty.

8.7.2.2.3 Black carbon and organic carbon

Most of the metric values for BC in the literature include the aerosol–radiation interaction and the snow/ice albedo effect of BC, though whether external or internal mixing is used varies between the studies. Bond et al. (2011) calculate GWPs and find that when the albedo effect is included the values increase by 5 to 15%. Studies have shown, however, that the climate response per unit forcing to this mechanism is stronger than for WMGHG (see Section 7.5).

Bond et al. (2013) assessed the current understanding of BC effects and calculated GWP and GTP for BC that includes aerosol–radiation interaction, aerosol–cloud interactions and albedo. As shown in Table 8.A.6 the uncertainties are wide for both metrics (for 90% uncertainty range) reflecting the current challenges related to understanding and quantifying the various effects (see Sections 7.5, 8.3.4 and 8.5.1). Their aerosol–radiation interaction effect is about 65% of the total effect while the albedo effect is approximately 20% of the aerosol–radiation interaction effect. Based on two studies (Rypdal et al., 2009; Bond et al., 2011), the GWP and GTP metrics were found to vary with the region where BC is emitted by about ±30% . For larger regions of emissions, Collins et al. (2013) calculated GWPs and GTPs for the direct effect of BC and found somewhat lower variations among the regions.

Several studies have focused on the effects of emissions of BC and OC from different regions (Bauer et al., 2007; Koch et al., 2007; Naik et al., 2007; Reddy and Boucher, 2007; Rypdal et al., 2009). However, examination of results from these models (Fuglestvedt et al., 2010) reveals that there is not a robust relationship between the region of emission and the metric value — hence, regions that yield the highest metric value in one study, do not, in general, do so in the other studies.

The metric values for OC are quite consistent across studies, but fewer studies are available (see Table 8.A.6). A brief overview of metric values for other components is given in the Supplementary Material Section 8.SM.14.

8.7.2.2.4 Summary of status of metrics for near-term climate forcers

The metrics provide a format for comparing the magnitudes of the various emissions as well as for comparing effects of emissions from different regions. They can also be used for comparing results from different studies. Much of the spread in results is due to differences in experimental design and how the models treat physical and chemical processes. Unlike most of the WMGHGs, many of the NTCFs are tightly coupled to the hydrologic cycle and atmospheric chemistry, leading to a much larger spread in results as these are highly complex processes that are difficult to validate on the requisite small spatial and short temporal scales. The confidence level is lower for many of the NTCF compared to WMGHG and much lower where aerosol–cloud interactions are important (see Section 8.5.1). There are particular difficulties for NO_X, because the net impact is a small residual of opposing effects with quite different spatial distributions and temporal behaviour. Although climate–carbon feedbacks for non-CO_2 emissions have not been included in the NTCF metrics (other than CH_4) presented here, they can greatly increase those values (Collins et al., 2013) and likely provide more realistic results.

8.7.2.3 Impact by Emitted Component

We now use the metrics evaluated here to estimate climate impacts of various components (in a forward looking perspective). Figure 8.32 shows global anthropogenic emissions of some selected components weighted by the GWP and GTP. The time horizons are chosen as examples and illustrate how the perceived impacts of components—relative to the impact of the reference gas—vary strongly as function of impact parameter (integrated RF in GWP or end-point temperature in GTP) and with time horizon.

We may also calculate the temporal development of the temperature responses to pulse or sustained emissions using the AGTP metric. Figure 8.33 shows that for a one-year pulse the impacts of NTCF decay quickly owing to their atmospheric adjustment times even if effects are prolonged due to climate response time (in the case of constant emissions the effects reach approximately constant levels since the emissions are replenished each year, except for CO_2, which has a fraction

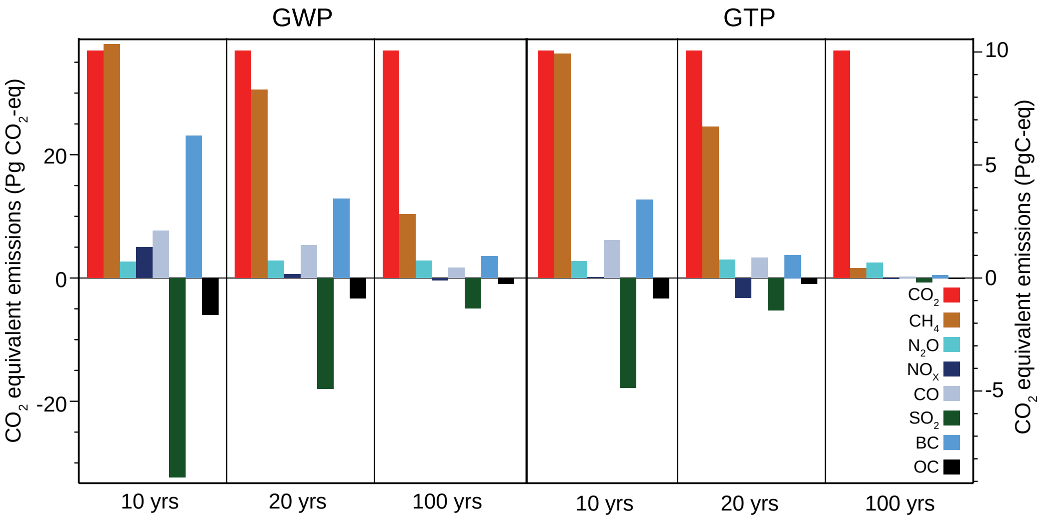


Figure 8.32 | Global anthropogenic emissions weighted by GWP and GTP for chosen time horizons (aerosol–cloud interactions are not included). Emission data for 2008 are taken from the EDGAR database. For BC and OC emissions for 2005 are from Shindell et al. (2012a). The units are 'CO$_2$ equivalents' which reflects equivalence only in the impact parameter of the chosen metric (integrated RF over the chosen time horizon for GWP; temperature change at the chosen point in time for GTP), given as Pg(CO$_2$)$_{eq}$ (left axis) and given as PgC$_{eq}$ (right axis). There are large uncertainties related to the metric values and consequentially also to the calculated CO$_2$ equivalents (see text).

remaining in the atmosphere on time scales of centuries). Figure 8.33 also shows how some components have strong short-lived effects of both signs while CO$_2$ has a weaker initial effect but one that persists to create a long-lived warming effect. Note that there are large uncertainties related to the metric values (as discussed in Section 8.7.1.4); especially for the NTCFs.

These examples show that the outcome of comparisons of effects of emissions depends strongly on choice of time horizon and metric type. Such end-user choices will have a strong influence on the calculated contributions from NTCFs versus WMGHGs or non-CO$_2$ versus CO$_2$ emissions. Thus, each specific analysis should use a design chosen in light of the context and questions being asked.

8.7.2.4 Metrics and Impacts by Sector

While the emissions of WMGHGs vary strongly between sectors, the climate impacts of these gases are independent of sector. The latter is not the case for chemically active and short-lived components, due to the dependence of their impact on the emission location. Since most sectors have multiple co-emissions, and for NTCFs some of these are warming while others are cooling, the net impact of a given sector requires explicit calculations. Since AR4, there has been significant progress in the understanding and quantification of climate impacts of NTCFs from sectors such as transportation, power production and biomass burning (Berntsen and Fuglestvedt, 2008; Skeie et al., 2009; Stevenson and Derwent, 2009; Lee et al., 2010; Unger et al., 2010; Dahlmann et al., 2011). Supplementary Material Table 8.SM.18 gives an overview of recent published metric values for various components by sector.

The impact from sectors depends on choice of metric, time horizon, pulse versus sustained emissions and forward versus backward looking perspective (see Section 8.7.1 and Box 8.4). Unger et al. (2010) calculated RF for a set of components emitted from each sector. RF at chosen points in time (20 and 100 years) for *sustained* emissions was used by Unger et al. (2010) as the metric for comparison. This is comparable to using integrated RF up to the chosen times for *pulse* emissions (as in GWPs). Such studies are relevant for policymaking that focuses on regulating the *total activity* of a sector or for understanding the contribution from a sector to climate change. On the other hand, the fixed mix of emissions makes it less general and relevant for emission scenarios. Alternatively, one may adopt a component-by-component view which is relevant for policies directed towards specific components (or sets of components, as controlling an individual pollutant in isolation is usually not practical). But this view will not capture interactions and non-linearities within the suite of components emitted by most sectors. The effects of specific emission control technologies or policies or projected societal changes on the mix of emissions is probably the most relevant type of analysis, but there are an enormous number of possible actions and regional details that could be investigated. Henze et al. (2012) demonstrate a method for providing highly spatially resolved

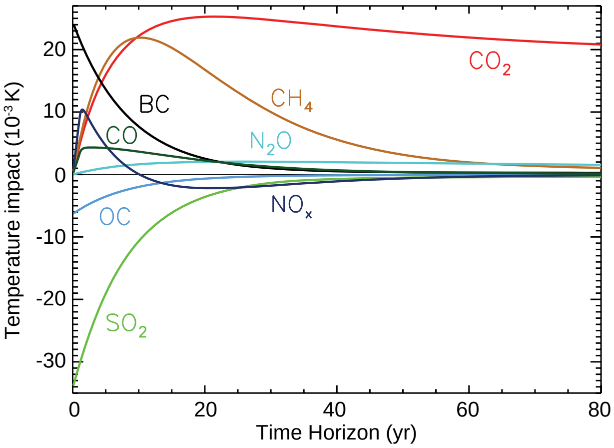


Figure 8.33 | Temperature response by component for total anthropogenic emissions for a 1-year pulse. Emission data for 2008 are taken from the EDGAR database and for BC and OC for 2005 from Shindell et al. (2012a). There are large uncertainties related to the AGTP values and consequentially also to the calculated temperature responses (see text).

estimates of forcing per component, and caution that RF aggregated over regions or sectors may not represent the impacts of emissions changes on finer scales.

Metrics for individual land-based sectors are often similar to the global mean metric values (Shindell et al., 2008). In contrast, metrics for emissions from aviation and shipping usually show large differences from global mean metric values (Table 8.A.3 versus Table 8.SM.18). Though there can sometimes be substantial variation in the impact of land-based sectors across regions, and for a particular region even from one sector to another, variability between different land-based sources is generally smaller than between land, sea and air emissions.

NO_x from aviation is one example where the metric type is especially important. GWP_{20} values are positive due to the strong response of short-lived ozone. Reported GWP_{100} and GTP_{100} values are of either sign, however, due to the differences in balance between the individual effects modelled. Even if the models agree on the net effect of NO_X, the individual contributions can differ significantly, with large uncertainties stemming from the relative magnitudes of the CH_4 and O_3 responses (Myhre et al., 2011) and the background tropospheric concentrations of NO_X (Holmes et al., 2011; Stevenson and Derwent, 2009). Köhler et al. (2013), find strong regional sensitivity of ozone and CH_4 to NO_X particularly at cruise altitude. Generally, they find the strongest effects at low latitudes. For the aviation sector contrails and contrail induced cirrus are also important. Based on detailed studies in the literature, Fuglestvedt et al. (2010) produced GWP and GTP for contrails, water vapor and contrail-induced cirrus.

The GWP and GTPs for NO_X from shipping are strongly negative for all time horizons. The strong positive effect via O_3 due to the low-NO_X environment into which ships generally emit NO_X is outweighed by the stronger effect on CH_4 destruction due to the relatively lower latitudes of these emissions compared to land-based sources.

In addition to having large emissions of NO_X the shipping sector has large emission of SO_2. The direct GWP_{100} for shipping ranges from –11 to –43 (see Supplementary Material Table 8.SM.18). Lauer et al. (2007) reported detailed calculations of the indirect forcing specifically for this sector and found a wide spread of values depending on the emission inventory. Righi et al. (2011) and Peters et al. (2012) calculate indirect effects that are 30 to 50% lower than the indirect forcing reported by Lauer et al. (2007). The values from Shindell and Faluvegi (2010) for SO_2 from power generation are similar to those for shipping.

Although the various land transport sectors often are treated as one aggregate (e.g., road transport) there are important subdivisions. For instance, Bond et al. (2013) points out that among the BC-rich sectors they examined, diesel vehicles have the most clearly positive net impact on forcing. Studies delving even further have shown substantial differences between trucks and cars, gasoline and diesel vehicles, and low-sulphur versus high-sulphur fuels. Similarly, for power production there are important differences depending on fuel type (coal, oil, gas; e.g., Shindell and Faluvegi, 2010).

In the assessment of climate impacts of current emissions by sectors we give examples and apply a forward-looking perspective on effects in terms of temperature change. The AGTP concept can be used to study the effects of the various components for chosen time horizons. A single year's worth of current global emissions from the energy and industrial sectors have the largest contributions to warming after 100 years (see Figure 8.34a). Household fossil fuel and biofuel, biomass burning and on-road transportation are also relatively large contributors to warming over 100-year time scales. Those same sectors, along with sectors that emit large amounts of CH_4 (animal husbandry, waste/landfills and agriculture), are most important over shorter time horizons (about 20 years; see Figure 8.34b).

Analysing climate change impacts by using the net effect of particular activities or sectors may—compared to other perspectives—provide more insight into how societal actions influence climate. Owing to large variations in mix of short- and long-lived components, as well as cooling and warming effects, the results will also in these cases depend strongly on choice of time horizon and climate impact parameter. Improved understanding of aerosol–cloud interactions, and how those are attributed to individual components is clearly necessary to refine estimates of sectoral or emitted component impacts.

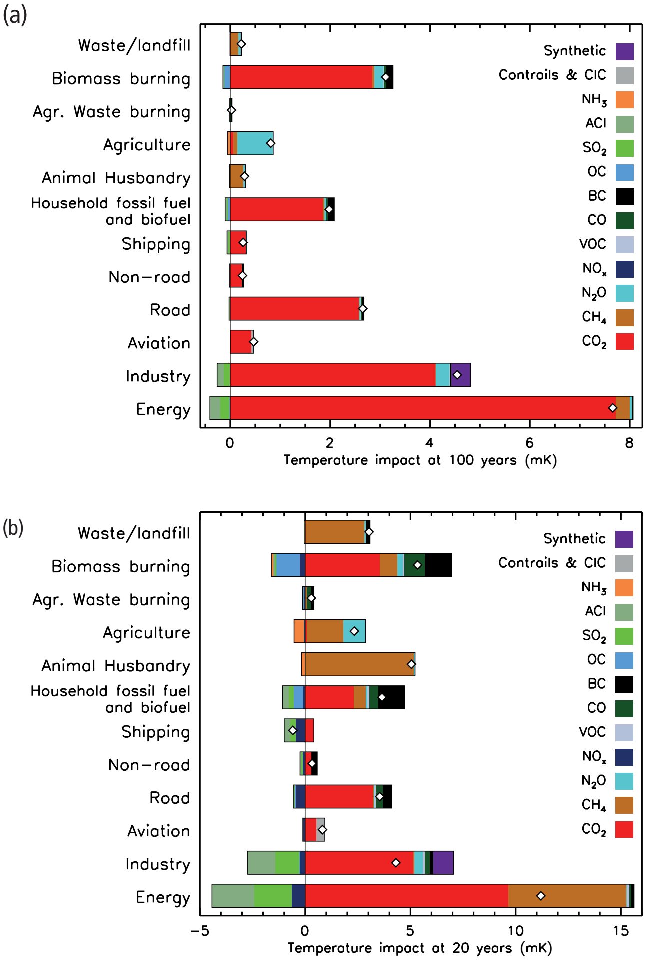


Figure 8.34 | Net global mean temperature change by source sector after (a) 100 and (b) 20 years (for 1-year pulse emissions). Emission data for 2008 are taken from the EDGAR database. For BC and OC anthropogenic emissions are from Shindell et al. (2012a) and biomass burning emissions are from Lamarque et al. (2010), see Supplementary Material Section 8.SM.17. There are large uncertainties related to the AGTP values and consequentially also to the calculated temperature responses (see text).

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Appendix 8.A: Lifetimes, Radiative Efficiencies and Metric Values

Table 8.A.1 | Radiative efficiencies (REs), lifetimes/adjustment times, AGWP and GWP values for 20 and 100 years, and AGTP and GTP values for 20, 50 and 100 years. Climate–carbon feedbacks are included for CO_2 while no climate feedbacks are included for the other components (see discussion in Sections 8.7.1.4 and 8.7.2.1, Supplementary Material and notes below the table; Supplementary Material Table 8.SM.16 gives analogous values including climate–carbon feedbacks for non-CO_2 emissions). For a complete list of chemical names and CAS numbers, and for accurate replications of metric values, see Supplementary Material Section 8.SM.13 and references therein.

Acronym, Common Name or Chemical Name	Chemical Formula	Lifetime (Years)	Radiative Efficiency (W m^{-2} ppb^{-1})	AGWP 20-year (W m^{-2} yr kg^{-1})	**GWP 20-year**	AGWP 100-year (W m^{-2} yr kg^{-1})	**GWP 100-year**	AGTP 20-year (K kg^{-1})	**GTP 20-year**	AGTP 50-year (K kg^{-1})	**GTP 50-year**	AGTP 100-year (K kg^{-1})	**GTP 100-year**
Carbon dioxide	CO_2	see*	1.37e-5	2.49e-14	1	9.17e-14	1	6.84e-16	1	6.17e-16	1	5.47e-16	1
Methane	CH_4	12.4†	3.63e-4	2.09e-12	84	2.61e-12	28	4.62e-14	67	8.69e-15	14	2.34e-15	4
Fossil methane‡	CH_4	12.4†	3.63e-4	2.11e-12	85	2.73e-12	30	4.68e-14	68	9.55e-15	15	3.11e-15	6
Nitrous Oxide	N_2O	121†	3.00e-3	6.58e-12	264	2.43e-11	265	1.89e-13	277	1.74e-13	282	1.28e-13	234
Chlorofluorocarbons													
CFC-11	CCl_3F	45.0	0.26	1.72e-10	6900	4.28e-10	4660	4.71e-12	6890	3.01e-12	4890	1.28e-12	2340
CFC-12	CCl_2F_2	100.0	0.32	2.69e-10	10,800	9.39e-10	10,200	7.71e-12	11,300	6.75e-12	11,000	4.62e-12	8450
CFC-13	$CClF_3$	640.0	0.25	2.71e-10	10,900	1.27e-09	13,900	7.99e-12	11,700	8.77e-12	14,200	8.71e-12	15,900
CFC-113	CCl_2FCClF_2	85.0	0.30	1.62e-10	6490	5.34e-10	5820	4.60e-12	6730	3.85e-12	6250	2.45e-12	4470
CFC-114	$CClF_2CClF_2$	190.0	0.31	1.92e-10	7710	7.88e-10	8590	5.60e-12	8190	5.56e-12	9020	4.68e-12	8550
CFC-115	$CClF_2CF_3$	1,020.0	0.20	1.46e-10	5860	7.03e-10	7670	4.32e-12	6310	4.81e-12	7810	4.91e-12	8980
Hydrochlorofluorocarbons													
HCFC-21	$CHCl_2F$	1.7	0.15	1.35e-11	543	1.35e-11	148	1.31e-13	192	1.59e-14	26	1.12e-14	20
HCFC-22	$CHClF_2$	11.9	0.21	1.32e-10	5280	1.62e-10	1760	2.87e-12	4200	5.13e-13	832	1.43e-13	262
HCFC-122	$CHCl_2CF_2Cl$	1.0	0.17	5.43e-12	218	5.43e-12	59	4.81e-14	70	6.25e-15	10	4.47e-15	8
HCFC-122a	$CHFClCFCl_2$	3.4	0.21	2.36e-11	945	2.37e-11	258	2.91e-13	426	2.99e-14	48	1.96e-14	36
HCFC-123	$CHCl_2CF_3$	1.3	0.15	7.28e-12	292	7.28e-12	79	6.71e-14	98	8.45e-15	14	6.00e-15	11
HCFC-123a	$CHClFCF_2Cl$	4.0	0.23	3.37e-11	1350	3.39e-11	370	4.51e-13	659	4.44e-14	72	2.81e-14	51
HCFC-124	$CHClFCF_3$	5.9	0.20	4.67e-11	1870	4.83e-11	527	7.63e-13	1120	7.46e-14	121	4.03e-14	74
HCFC-132c	CH_2FCFCl_2	4.3	0.17	3.07e-11	1230	3.10e-11	338	4.27e-13	624	4.14e-14	67	2.58e-14	47
HCFC-141b	CH_3CCl_2F	9.2	0.16	6.36e-11	2550	7.17e-11	782	1.27e-12	1850	1.67e-13	271	6.09e-14	111
HCFC-142b	CH_3CClF_2	17.2	0.19	1.25e-10	5020	1.82e-10	1980	3.01e-12	4390	8.46e-13	1370	1.95e-13	356
HCFC-225ca	$CHCl_2CF_2CF_3$	1.9	0.22	1.17e-11	469	1.17e-11	127	1.17e-13	170	1.38e-14	22	9.65e-15	18
HCFC-225cb	$CHClFCF_2CClF_2$	5.9	0.29	4.65e-11	1860	4.81e-11	525	7.61e-13	1110	7.43e-14	120	4.01e-14	73
(E)-1-Chloro-3,3,3-trifluoroprop-1-ene	trans-$CF_3CH{=}CHCl$	26.0 days	0.04	1.37e-13	5	1.37e-13	1	1.09e-15	2	1.54e-16	<1	1.12e-16	<1

(continued on next page)

Table 8.A.1 *(continued)*

Acronym, Common Name or Chemical Name	Chemical Formula	Lifetime (Years)	Radiative Efficiency (W m^{-2} ppb^{-1})	AGWP 20-year (W m^{-2} yr kg^{-1})	GWP 20-year	AGWP 100-year (W m^{-2} yr kg^{-1})	GWP 100-year	AGTP 20-year (K kg^{-1})	GTP 20-year	AGTP 50-year (K kg^{-1})	GTP 50-year	AGTP 100-year (K kg^{-1})	GTP 100-year
Hydrofluorocarbons													
HFC-23	CHF_3	222.0	0.18	2.70e-10	10,800	1.14e-09	12,400	7.88e-12	11,500	7.99e-12	13,000	6.95e-12	12,700
HFC-32	CH_2F_2	5.2	0.11	6.07e-11	2430	6.21e-11	677	9.32e-13	1360	8.93e-14	145	5.17e-14	94
HFC-41	CH_3F	2.8	0.02	1.07e-11	427	1.07e-11	116	1.21e-13	177	1.31e-14	21	8.82e-15	16
HFC-125	CHF_2CF_3	28.2	0.23	1.52e-10	6090	2.91e-10	3170	3.97e-12	5800	1.84e-12	2980	5.29e-13	967
HFC-134	CHF_2CHF_2	9.7	0.19	8.93e-11	3580	1.02e-10	1120	1.82e-12	2660	2.54e-13	412	8.73e-14	160
HFC-134a	CH_2FCF_3	13.4	0.16	9.26e-11	3710	1.19e-10	1300	2.09e-12	3050	4.33e-13	703	1.10e-13	201
HFC-143	CH_2FCHF_2	3.5	0.13	3.00e-11	1200	3.01e-11	328	3.76e-13	549	3.82e-14	62	2.49e-14	46
HFC-143a	CH_3CF_3	47.1	0.16	1.73e-10	6940	4.41e-10	4800	4.76e-12	6960	3.12e-12	5060	1.37e-12	2500
HFC-152	CH_2FCH_2F	0.4	0.04	1.51e-12	60	1.51e-12	16	1.25e-14	18	1.71e-15	3	1.24e-15	2
HFC-152a	CH_3CHF_2	1.5	0.10	1.26e-11	506	1.26e-11	138	1.19e-13	174	1.47e-14	24	1.04e-14	19
HFC-161	CH_3CH_2F	66.0 days	0.02	3.33e-13	13	3.33e-13	4	2.70e-15	4	3.76e-16	<1	2.74e-16	<1
HFC-227ca	$CF_3CF_2CHF_2$	28.2	0.27	1.27e-10	5080	2.42e-10	2640	3.31e-12	4830	1.53e-12	2480	4.41e-13	806
HFC-227ea	CF_3CHFCF_3	38.9	0.26	1.34e-10	5360	3.07e-10	3350	3.61e-12	5280	2.12e-12	3440	7.98e-13	1460
HFC-236cb	$CH_2FCF_2CF_3$	13.1	0.23	8.67e-11	3480	1.11e-10	1210	1.94e-12	2840	3.92e-13	636	1.01e-13	185
HFC-236ea	CHF_2CHFCF_3	11.0	0.30[a]	1.03e-10	4110	1.22e-10	1330	2.18e-12	3190	3.53e-13	573	1.06e-13	195
HFC-236fa	$CF_3CH_2CF_3$	242.0	0.24	1.73e-10	6940	7.39e-10	8060	5.06e-12	7400	5.18e-12	8400	4.58e-12	8380
HFC-245ca	$CH_2FCF_2CHF_2$	6.5	0.24[b]	6.26e-11	2510	6.56e-11	716	1.07e-12	1570	1.09e-13	176	5.49e-14	100
HFC-245cb	$CF_3CF_2CH_3$	47.1	0.24	1.67e-10	6680	4.24e-10	4620	4.58e-12	6690	3.00e-12	4870	1.32e-12	2410
HFC-245ea	$CHF_2CHFCHF_2$	3.2	0.16[c]	2.15e-11	863	2.16e-11	235	2.59e-13	378	2.70e-14	44	1.79e-14	33
HFC-245eb	$CH_2FCHFCF_3$	3.1	0.20[c]	2.66e-11	1070	2.66e-11	290	3.15e-13	460	3.31e-14	54	2.20e-14	40
HFC-245fa	$CHF_2CH_2CF_3$	7.7	0.24	7.29e-11	2920	7.87e-11	858	1.35e-12	1970	1.51e-13	245	6.62e-14	121
HFC-263fb	$CH_3CH_2CF_3$	1.2	0.10[c]	6.93e-12	278	6.93e-12	76	6.31e-14	92	8.02e-15	13	5.70e-15	10
HFC-272ca	$CH_3CF_2CH_3$	2.6	0.07	1.32e-11	530	1.32e-11	144	1.46e-13	213	1.61e-14	26	1.09e-14	20
HFC-329p	$CHF_2CF_2CF_2CF_3$	28.4	0.31	1.13e-10	4510	2.16e-10	2360	2.94e-12	4290	1.37e-12	2220	3.96e-13	725
HFC-365mfc	$CH_3CF_2CH_2CF_3$	8.7	0.22	6.64e-11	2660	7.38e-11	804	1.30e-12	1890	1.62e-13	262	6.24e-14	114
HFC-43-10mee	$CF_3CHFCHFCF_2CF_3$	16.1	0.42[b]	1.08e-10	4310	1.51e-10	1650	2.54e-12	3720	6.62e-13	1070	1.54e-13	281
HFC-1132a	$CH_2=CF_2$	4.0 days	0.004[d]	3.87e-15	<1	3.87e-15	<1	3.08e-17	<1	4.35e-18	<1	3.18e-18	<1
HFC-1141	$CH_2=CHF$	2.1 days	0.002[d]	1.54e-15	<1	1.54e-15	<1	1.23e-17	<1	1.73e-18	<1	1.27e-18	<1
(Z)-HFC-1225ye	$CF_3CF=CHF(Z)$	8.5 days	0.02	2.14e-14	<1	2.14e-14	<1	1.70e-16	<1	2.40e-17	<1	1.76e-17	<1
(E)-HFC-1225ye	$CF_3CF=CHF(E)$	4.9 days	0.01	7.25e-15	<1	7.25e-15	<1	5.77e-17	<1	8.14e-18	<1	5.95e-18	<1
(Z)-HFC-1234ze	$CF_3CH=CHF(Z)$	10.0 days	0.02	2.61e-14	1	2.61e-14	<1	2.08e-16	<1	2.93e-17	<1	2.14e-17	<1
HFC-1234yf	$CF_3CF=CH_2$	10.5 days	0.02	3.22e-14	1	3.22e-14	<1	2.57e-16	<1	3.62e-17	<1	2.65e-17	<1
(E)-HFC-1234ze	trans-$CF_3CH=CHF$	16.4 days	0.04	8.74e-14	4	8.74e-14	<1	6.98e-16	<1	9.82e-17	<1	7.18e-17	<1
(Z)-HFC-1336	$CF_3CH=CHCF_3(Z)$	22.0 days	0.07[d]	1.54e-13	6	1.54e-13	2	1.23e-15	2	1.73e-16	<1	1.26e-16	<1

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Table 8.A.1 *(continued)*

Acronym, Common Name or Chemical Name	**Chemical Formula**	Lifetime (Years)	Radiative Efficiency (W m^{-2} ppb^{-1})	AGWP 20-year (W m^{-2} yr kg^{-1})	**GWP 20-year**	AGWP 100-year (W m^{-2} yr kg^{-1})	**GWP 100-year**	AGTP 20-year (K kg^{-1})	**GTP 20-year**	AGTP 50-year (K kg^{-1})	**GTP 50-year**	AGTP 100-year (K kg^{-1})	**GTP 100-year**
HFC-1243zf	$CF_3CH{=}CH_2$	7.0 days	0.01	1.37e-14	**1**	1.37e-14	**<1**	1.09e-16	**<1**	1.53e-17	**<1**	1.12e-17	**<1**
HFC-1345zfc	$C_2F_5CH{=}CH_2$	7.6 days	0.01	1.15e-14	**<1**	1.15e-14	**<1**	9.19e-17	**<1**	1.30e-17	**<1**	9.48e-18	**<1**
3,3,4,4,5,5,6,6,6-Nonafluorohex-1-ene	$C_4F_9CH{=}CH_2$	7.6 days	0.03	1.25e-14	**<1**	1.25e-14	**<1**	9.92e-17	**<1**	1.40e-17	**<1**	1.02e-17	**<1**
3,3,4,4,5,5,6,6,7,7,8,8,8-Tridecafluorooct-1-ene	$C_6F_{13}CH{=}CH_2$	7.6 days	0.03	9.89e-15	**<1**	9.89e-15	**<1**	7.87e-17	**<1**	1.11e-17	**<1**	8.12e-18	**<1**
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,10-Heptadecafluorodec-1-ene	$C_8F_{17}CH{=}CH_2$	7.6 days	0.03	8.52e-15	**<1**	8.52e-15	**<1**	6.79e-17	**<1**	9.57e-18	**<1**	7.00e-18	**<1**
Chlorocarbons and Hydrochlorocarbons													
Methyl chloroform	CH_3CCl_3	5.0	0.07	1.44e-11	**578**	1.47e-11	**160**	2.17e-13	**317**	2.07e-14	**34**	1.22e-14	**22**
Carbon tetrachloride	CCl_4	26.0	0.17	8.69e-11	**3480**	1.59e-10	**1730**	2.24e-12	**3280**	9.68e-13	**1570**	2.62e-13	**479**
Methyl chloride	CH_3Cl	1.0	0.01[a]	1.12e-12	**45**	1.12e-12	**12**	9.93e-15	**15**	1.29e-15	**2**	9.20e-16	**2**
Methylene chloride	CH_2Cl_2	0.4	0.03[b]	8.18e-13	**33**	8.18e-13	**9**	6.78e-15	**10**	9.26e-16	**2**	6.72e-16	**1**
Chloroform	$CHCl_3$	0.4	0.08	1.50e-12	**60**	1.50e-12	**16**	1.25e-14	**18**	1.70e-15	**3**	1.24e-15	**2**
1,2-Dichloroethane	CH_2ClCH_2Cl	65.0 days	0.01	8.24e-14	**3**	8.24e-14	**<1**	6.67e-16	**<1**	9.29e-17	**<1**	6.77e-17	**<1**
Bromocarbons, Hydrobromocarbons and Halons													
Methyl bromide	CH_3Br	0.8	0.004	2.16e-13	**9**	2.16e-13	**2**	1.87e-15	**3**	2.47e-16	**<1**	1.78e-16	**<1**
Methylene bromide	CH_2Br_2	0.3	0.01	9.31e-14	**4**	9.31e-14	**1**	7.66e-16	**1**	1.05e-16	**<1**	7.65e-17	**<1**
Halon-1201	$CHBrF_2$	5.2	0.15	3.37e-11	**1350**	3.45e-11	**376**	5.17e-13	**756**	4.96e-14	**80**	2.87e-14	**52**
Halon-1202	CBr_2F_2	2.9	0.27	2.12e-11	**848**	2.12e-11	**231**	2.43e-13	**356**	2.61e-14	**42**	1.75e-14	**32**
Halon-1211	$CBrClF_2$	16.0	0.29	1.15e-10	**4590**	1.60e-10	**1750**	2.70e-12	**3950**	6.98e-13	**1130**	1.62e-13	**297**
Halon-1301	$CBrF_3$	65.0	0.30	1.95e-10	**7800**	5.77e-10	**6290**	5.46e-12	**7990**	4.16e-12	**6750**	2.28e-12	**4170**
Halon-2301	CH_2BrCF_3	3.4	0.14	1.59e-11	**635**	1.59e-11	**173**	1.96e-13	**286**	2.01e-14	**33**	1.32e-14	**24**
Halon-2311 / Halothane	$CHBrClCF_3$	1.0	0.13	3.77e-12	**151**	3.77e-12	**41**	3.35e-14	**49**	4.34e-15	**7**	3.10e-15	**6**
Halon-2401	$CHFBrCF_3$	2.9	0.19	1.68e-11	**674**	1.68e-11	**184**	1.94e-13	**283**	2.07e-14	**34**	1.39e-14	**25**
Halon-2402	$CBrF_2CBrF_2$	20.0	0.31	8.59e-11	**3440**	1.35e-10	**1470**	2.12e-12	**3100**	7.08e-13	**1150**	1.66e-13	**304**
Fully Fluorinated Species													
Nitrogen trifluoride	NF_3	500.0	0.20	3.19e-10	**12,800**	1.47e-09	**16,100**	9.39e-12	**13,700**	1.02e-11	**16,500**	9.91e-12	**18,100**
Sulphur hexafluoride	SF_6	3,200.0	0.57	4.37e-10	**17,500**	2.16e-09	**23,500**	1.29e-11	**18,900**	1.47e-11	**23,800**	1.54e-11	**28,200**
(Trifluoromethyl) sulphur pentafluoride	SF_5CF_3	800.0	0.59	3.36e-10	**13,500**	1.60e-09	**17,400**	9.93e-12	**14,500**	1.10e-11	**17,800**	1.11e-11	**20,200**
Sulphuryl fluoride	SO_2F_2	36.0	0.20	1.71e-10	**6840**	3.76e-10	**4090**	4.58e-12	**6690**	2.55e-12	**4140**	9.01e-13	**1650**
PFC-14	CF_4	50,000.0	0.09	1.22e-10	**4880**	6.08e-10	**6630**	3.61e-12	**5270**	4.12e-12	**6690**	4.40e-12	**8040**
PFC-116	C_2F_6	10,000.0	0.25	2.05e-10	**8210**	1.02e-09	**11,100**	6.07e-12	**8880**	6.93e-12	**11,200**	7.36e-12	**13,500**
PFC-c216	$c\text{-}C_3F_6$	3,000.0	0.23[e]	1.71e-10	**6850**	8.44e-10	**9200**	5.06e-12	**7400**	5.74e-12	**9310**	6.03e-12	**11,000**
PFC-218	C_3F_8	2,600.0	0.28	1.66e-10	**6640**	8.16e-10	**8900**	4.91e-12	**7180**	5.56e-12	**9010**	5.83e-12	**10,700**
PFC-318	$c\text{-}C_4F_8$	3,200.0	0.32	1.77e-10	**7110**	8.75e-10	**9540**	5.25e-12	**7680**	5.96e-12	**9660**	6.27e-12	**11,500**

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Table 8.A.1 (continued)

Acronym, Common Name or Chemical Name	Chemical Formula	Lifetime (Years)	Radiative Efficiency (W m^{-2} ppb^{-1})	AGWP 20-year (W m^{-2} yr kg^{-1})	**GWP 20-year**	AGWP 100-year (W m^{-2} yr kg^{-1})	**GWP 100-year**	AGTP 20-year (K kg^{-1})	**GTP 20-year**	AGTP 50-year (K kg^{-1})	**GTP 50-year**	AGTP 100-year (K kg^{-1})	**GTP 100-year**
PFC-31-10	C_4F_{10}	2,600.0	0.36	1.71e-10	**6870**	8.44e-10	**9200**	5.08e-12	**7420**	5.75e-12	**9320**	6.02e-12	**11,000**
Perfluorocyclopentene	$c\text{-}C_5F_8$	31.0 days	0.08[f]	1.71e-13	**7**	1.71e-13	**2**	1.37e-15	**2**	1.92e-16	**<1**	1.40e-16	**<1**
PFC-41-12	$n\text{-}C_5F_{12}$	4,100.0	0.41	1.58e-10	**6350**	7.84e-10	**8550**	4.69e-12	**6860**	5.33e-12	**8650**	5.62e-12	**10,300**
PFC-51-14	$n\text{-}C_6F_{14}$	3,100.0	0.44	1.47e-10	**5890**	7.26e-10	**7910**	4.35e-12	**6370**	4.94e-12	**8010**	5.19e-12	**9490**
PFC-61-16	$n\text{-}C_7F_{16}$	3,000.0	0.50	1.45e-10	**5830**	7.17e-10	**7820**	4.31e-12	**6290**	4.88e-12	**7920**	5.13e-12	**9380**
PFC-71-18	C_8F_{18}	3,000.0	0.55	1.42e-10	**5680**	6.99e-10	**7620**	4.20e-12	**6130**	4.76e-12	**7710**	5.00e-12	**9140**
PFC-91-18	$C_{10}F_{18}$	2,000.0	0.55	1.34e-10	**5390**	6.59e-10	**7190**	3.98e-12	**5820**	4.49e-12	**7290**	4.68e-12	**8570**
Perfluorodecalin (cis)	$Z\text{-}C_{10}F_{18}$	2,000.0	0.56	1.35e-10	**5430**	6.64e-10	**7240**	4.01e-12	**5860**	4.52e-12	**7340**	4.72e-12	**8630**
Perfluorodecalin (trans)	$E\text{-}C_{10}F_{18}$	2,000.0	0.48	1.18e-10	**4720**	5.77e-10	**6290**	3.48e-12	**5090**	3.93e-12	**6380**	4.10e-12	**7500**
PFC-1114	$CF_2=CF_2$	1.1 days	0.002	2.68e-16	**<1**	2.68e-16	**<1**	2.13e-18	**<1**	3.00e-19	**<1**	2.20e-19	**<1**
PFC-1216	$CF_3CF=CF_2$	4.9 days	0.01	6.42e-15	**<1**	6.42e-15	**<1**	5.11e-17	**<1**	7.21e-18	**<1**	5.27e-18	**<1**
Perfluorobuta-1,3-diene	$CF_2=CFCF=CF_2$	1.1 days	0.003	3.29e-16	**<1**	3.29e-16	**<1**	2.61e-18	**<1**	3.69e-19	**<1**	2.70e-19	**<1**
Perfluorobut-1-ene	$CF_3CF_2CF=CF_2$	6.0 days	0.02	8.38e-15	**<1**	8.38e-15	**<1**	6.67e-17	**<1**	9.41e-18	**<1**	6.88e-18	**<1**
Perfluorobut-2-ene	$CF_3CF=CFCF_3$	31.0 days	0.07	1.62e-13	**6**	1.62e-13	**2**	1.30e-15	**2**	1.82e-16	**<1**	1.33e-16	**<1**
Halogenated Alcohols and Ethers													
HFE-125	CHF_2OCF_3	119.0	0.41	3.10e-10	**12,400**	1.14e-09	**12,400**	8.91e-12	**13,000**	8.14e-12	**13,200**	5.97e-12	**10,900**
HFE-134 (HG-00)	CHF_2OCHF_2	24.4	0.44	2.90e-10	**11,600**	5.10e-10	**5560**	7.42e-12	**10,800**	3.02e-12	**4900**	7.83e-13	**1430**
HFE-143a	CH_3OCF_3	4.8	0.18	4.72e-11	**1890**	4.80e-11	**523**	6.95e-13	**1020**	6.66e-14	**108**	3.99e-14	**73**
HFE-227ea	$CF_3CHFOCF_3$	51.6	0.44	2.22e-10	**8900**	5.92e-10	**6450**	6.15e-12	**8980**	4.22e-12	**6850**	1.98e-12	**3630**
HCFE-235ca2 (enflurane)	CHF_2OCF_2CHFCl	4.3	0.41	5.30e-11	**2120**	5.35e-11	**583**	7.36e-13	**1080**	7.14e-14	**116**	4.44e-14	**81**
HCFE-235da2 (isoflurane)	$CHF_2OCHClCF_3$	3.5	0.42	4.49e-11	**1800**	4.50e-11	**491**	5.62e-13	**822**	5.72e-14	**93**	3.73e-14	**68**
HFE-236ca	$CHF_2OCF_2CHF_2$	20.8	0.56[g]	2.42e-10	**9710**	3.89e-10	**4240**	6.03e-12	**8820**	2.10e-12	**3400**	4.98e-13	**912**
HFE-236ea2 (desflurane)	$CHF_2OCHFCF_3$	10.8	0.45	1.39e-10	**5550**	1.64e-10	**1790**	2.93e-12	**4280**	4.64e-13	**753**	1.42e-13	**260**
HFE-236fa	$CF_3CH_2OCF_3$	7.5	0.36	8.35e-11	**3350**	8.98e-11	**979**	1.53e-12	**2240**	1.68e-13	**273**	7.54e-14	**138**
HFE-245cb2	$CF_3CF_2OCH_3$	4.9	0.33	5.90e-11	**2360**	6.00e-11	**654**	8.77e-13	**1280**	8.40e-14	**136**	4.99e-14	**91**
HFE-245fa1	$CHF_2CH_2OCF_3$	6.6	0.31	7.22e-11	**2900**	7.59e-11	**828**	1.25e-12	**1820**	1.27e-13	**206**	6.35e-14	**116**
HFE-245fa2	$CHF_2OCH_2CF_3$	5.5	0.36	7.25e-11	**2910**	7.45e-11	**812**	1.15e-12	**1670**	1.10e-13	**179**	6.21e-14	**114**
2,2,3,3,3-Pentafluoropropan-1-ol	$CF_3CF_2CH_2OH$	0.3	0.14	1.72e-12	**69**	1.72e-12	**19**	1.42e-14	**21**	1.95e-15	**3**	1.42e-15	**3**
HFE-254cb1	$CH_3OCF_2CHF_2$	2.5	0.26	2.76e-11	**1110**	2.76e-11	**301**	2.99e-13	**438**	3.34e-14	**54**	2.28e-14	**42**
HFE-263fb2	$CF_3CH_2OCH_3$	23.0 days	0.04	1.22e-13	**5**	1.22e-13	**1**	9.72e-16	**1**	1.37e-16	**<1**	9.98e-17	**<1**
HFE-263m1	$CF_3OCH_2CH_3$	0.4	0.13	2.70e-12	**108**	2.70e-12	**29**	2.25e-14	**33**	3.06e-15	**5**	2.22e-15	**4**
3,3,3-Trifluoropropan-1-ol	$CF_3CH_2CH_2OH$	12.0 days	0.02	3.57e-14	**1**	3.57e-14	**<1**	2.85e-16	**<1**	4.01e-17	**<1**	2.93e-17	**<1**
HFE-329mcc2	$CHF_2CF_2OCF_2CF_3$	22.5	0.53	1.68e-10	**6720**	2.81e-10	**3070**	4.23e-12	**6180**	1.59e-12	**2580**	3.93e-13	**718**
HFE-338mmz1	$(CF_3)_2CHOCHF_2$	21.2	0.44	1.48e-10	**5940**	2.40e-10	**2620**	3.70e-12	**5410**	1.31e-12	**2130**	3.14e-13	**575**

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Table 8.A.1 (continued)

Acronym, Common Name or Chemical Name	Chemical Formula	Lifetime (Years)	Radiative Efficiency (W m⁻² ppb⁻¹)	AGWP 20-year (W m⁻² yr kg⁻¹)	**GWP 20-year**	AGWP 100-year (W m⁻² yr kg⁻¹)	**GWP 100-year**	AGTP 20-year (K kg⁻¹)	**GTP 20-year**	AGTP 50-year (K kg⁻¹)	**GTP 50-year**	AGTP 100-year (K kg⁻¹)	**GTP 100-year**
HFE-338mcf2	$CF_3CH_2OCF_2CF_3$	7.5	0.44	7.93e-11	**3180**	8.52e-11	**929**	1.45e-12	**2120**	1.60e-13	**259**	7.16e-14	**131**
Sevoflurane (HFE-347mmz1)	$(CF_3)_2CHOCH_2F$	2.2	0.32	1.98e-11	**795**	1.98e-11	**216**	2.06e-13	**302**	2.37e-14	**38**	1.64e-14	**30**
HFE-347mcc3 (HFE-7000)	$CH_3OCF_2CF_2CF_3$	5.0	0.35	4.78e-11	**1910**	4.86e-11	**530**	7.18e-13	**1050**	6.87e-14	**111**	4.05e-14	**74**
HFE-347mcf2	$CHF_2CH_2OCF_2CF_3$	6.6	0.42	7.45e-11	**2990**	7.83e-11	**854**	1.29e-12	**1880**	1.31e-13	**212**	6.55e-14	**120**
HFE-347pcf2	$CHF_2CF_2OCH_2CF_3$	6.0	0.48[h]	7.86e-11	**3150**	8.15e-11	**889**	1.30e-12	**1900**	1.27e-13	**206**	6.81e-14	**124**
HFE-347mmy1	$(CF_3)_2CFOCH_3$	3.7	0.32	3.32e-11	**1330**	3.33e-11	**363**	4.27e-13	**624**	4.28e-14	**69**	2.76e-14	**51**
HFE-356mec3	$CH_3OCF_2CHFCF_3$	3.8	0.30	3.53e-11	**1410**	3.55e-11	**387**	4.60e-13	**673**	4.58e-14	**74**	2.94e-14	**54**
HFE-356mff2	$CF_3CH_2OCH_2CF_3$	105.0 days	0.17	1.54e-12	**62**	1.54e-12	**17**	1.26e-14	**18**	1.74e-15	**3**	1.26e-15	**2**
HFE-356pcf2	$CHF_2CH_2OCF_2CHF_2$	5.7	0.37	6.40e-11	**2560**	6.59e-11	**719**	1.03e-12	**1500**	9.97e-14	**162**	5.50e-14	**101**
HFE-356pcf3	$CHF_2OCH_2CF_2CHF_2$	3.5	0.38	4.08e-11	**1640**	4.09e-11	**446**	5.11e-13	**747**	5.20e-14	**84**	3.39e-14	**62**
HFE-356pcc3	$CH_3OCF_2CF_2CHF_2$	3.8	0.32	3.77e-11	**1510**	3.79e-11	**413**	4.91e-13	**718**	4.89e-14	**79**	3.14e-14	**57**
HFE-356mmz1	$(CF_3)_2CHOCH_3$	97.1 days	0.15	1.25e-12	**50**	1.25e-12	**14**	1.02e-14	**15**	1.41e-15	**2**	1.02e-15	**2**
HFE-365mcf3	$CF_3CF_2CH_2OCH_3$	19.3 days	0.05	8.51e-14	**3**	8.51e-14	**<1**	6.80e-16	**<1**	9.56e-17	**<1**	6.99e-17	**<1**
HFE-365mcf2	$CF_3CF_2OCH_2CH_3$	0.6	0.26[i]	5.35e-12	**215**	5.35e-12	**58**	4.53e-14	**66**	6.10e-15	**10**	4.40e-15	**8**
HFE-374pc2	$CHF_2CF_2OCH_2CH_3$	5.0	0.30	5.65e-11	**2260**	5.75e-11	**627**	8.48e-13	**1240**	8.12e-14	**132**	4.79e-14	**88**
4,4,4-Trifluorobutan-1-ol	$CF_3(CH_2)_2CH_2OH$	4.0 days	0.01	1.73e-15	**<1**	1.73e-15	**<1**	1.38e-17	**<1**	1.94e-18	**<1**	1.42e-18	**<1**
2,2,3,3,4,4,5,5-Octafluorocyclopentanol	$-(CF_2)_4CH(OH)-$	0.3	0.16	1.18e-12	**47**	1.18e-12	**13**	9.67e-15	**14**	1.33e-15	**2**	9.69e-16	**2**
HFE-43-10pccc124 (H-Galden 1040x, HG-11)	$CHF_2OCF_2OC_2F_4OCHF_2$	13.5	1.02	2.00e-10	**8010**	2.58e-10	**2820**	4.52e-12	**6600**	9.46e-13	**1530**	2.38e-13	**436**
HFE-449s1 (HFE-7100)	$C_4F_9OCH_3$	4.7	0.36	3.80e-11	**1530**	3.86e-11	**421**	5.54e-13	**809**	5.32e-14	**86**	3.21e-14	**59**
n-HFE-7100	$n\text{-}C_4F_9OCH_3$	4.7	0.42	4.39e-11	**1760**	4.45e-11	**486**	6.39e-13	**934**	6.14e-14	**99**	3.70e-14	**68**
i-HFE-7100	$i\text{-}C_4F_9OCH_3$	4.7	0.35	3.68e-11	**1480**	3.73e-11	**407**	5.35e-13	**783**	5.14e-14	**83**	3.10e-14	**57**
HFE-569sf2 (HFE-7200)	$C_4F_9OC_2H_5$	0.8	0.30	5.21e-12	**209**	5.21e-12	**57**	4.52e-14	**66**	5.97e-15	**10**	4.29e-15	**8**
n-HFE-7200	$n\text{-}C_4F_9OC_2H_5$	0.8	0.35[i]	5.92e-12	**237**	5.92e-12	**65**	5.14e-14	**75**	6.78e-15	**11**	4.87e-15	**9**
i-HFE-7200	$i\text{-}C_4F_9OC_2H_5$	0.8	0.24	4.06e-12	**163**	4.06e-12	**44**	3.52e-14	**52**	4.65e-15	**8**	3.34e-15	**6**
HFE-236ca12 (HG-10)	$CHF_2OCF_2OCHF_2$	25.0	0.65	2.75e-10	**11,000**	4.91e-10	**5350**	7.06e-12	**10,300**	2.94e-12	**4770**	7.75e-13	**1420**
HFE-338pcc13 (HG-01)	$CHF_2OCF_2CF_2OCHF_2$	12.9	0.86	2.10e-10	**8430**	2.67e-10	**2910**	4.69e-12	**6860**	9.28e-13	**1500**	2.42e-13	**442**
1,1,1,3,3,3-Hexafluoropropan-2-ol	$(CF_3)_2CHOH$	1.9	0.26	1.67e-11	**668**	1.67e-11	**182**	1.66e-13	**243**	1.97e-14	**32**	1.38e-14	**25**
HG-02	$HF_2C–(OCF_2CF_2)_2–OCF_2H$	12.9	1.24[i]	1.97e-10	**7900**	2.50e-10	**2730**	4.40e-12	**6430**	8.70e-13	**1410**	2.27e-13	**415**
HG-03	$HF_2C–(OCF_2CF_2)_3–OCF_2H$	12.9	1.76[i]	2.06e-10	**8270**	2.62e-10	**2850**	4.60e-12	**6730**	9.10e-13	**1480**	2.37e-13	**434**
HG-20	$HF_2C–(OCF_2)_2–OCF_2H$	25.0	0.92[i]	2.73e-10	**10,900**	4.86e-10	**5300**	7.00e-12	**10,200**	2.91e-12	**4730**	7.68e-13	**1400**
HG-21	$HF_2C–OCF_2CF_2OCF_2OCF_2O–CF_2H$	13.5	1.71[i]	2.76e-10	**11,100**	3.57e-10	**3890**	6.23e-12	**9110**	1.31e-12	**2120**	3.29e-13	**602**

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Table 8.A.1 *(continued)*

Acronym, Common Name or Chemical Name	Chemical Formula	Lifetime (Years)	Radiative Efficiency (W m^{-2} ppb^{-1})	AGWP 20-year (W m^{-2} yr kg^{-1})	**GWP 20-year**	AGWP 100-year (W m^{-2} yr kg^{-1})	**GWP 100-year**	AGTP 20-year (K kg^{-1})	**GTP 20-year**	AGTP 50-year (K kg^{-1})	**GTP 50-year**	AGTP 100-year (K kg^{-1})	**GTP 100-year**
HG-30	$HF_2C–(OCF_2)_3–OCF_2H$	25.0	1.65[i]	3.77e-10	**15,100**	6.73e-10	**7330**	9.68e-12	**14,100**	4.03e-12	**6530**	1.06e-12	**1940**
1-Ethoxy-1,1,2,2,3,3,3-heptafluoropropane	$CF_3CF_2CF_2OCH_2CH_3$	0.8	0.28[i]	5.56e-12	**223**	5.56e-12	**61**	4.80e-14	**70**	6.36e-15	**10**	4.57e-15	**8**
Fluoroxene	$CF_3CH_2OCH{=}CH_2$	3.6 days	0.01[i]	4.97e-15	**<1**	4.97e-15	**<1**	3.95e-17	**<1**	5.58e-18	**<1**	4.08e-18	**<1**
1,1,2,2-Tetrafluoro-1-(fluoromethoxy)ethane	$CH_2FOCF_2CF_2H$	6.2	0.34[i]	7.68e-11	**3080**	7.99e-11	**871**	1.29e-12	**1880**	1.28e-13	**207**	6.68e-14	**122**
2-Ethoxy-3,3,4,4,5-pentafluorotetrahydro-2,5-bis[1,2,2,2-tetrafluoro-1-(trifluoromethyl)ethyl]-furan	$C_{12}H_5F_{19}O_2$	1.0	0.49[i]	5.09e-12	**204**	5.09e-12	**56**	4.53e-14	**66**	5.86e-15	**10**	4.19e-15	**8**
Fluoro(methoxy)methane	CH_3OCH_2F	73.0 days	0.07[g]	1.15e-12	**46**	1.15e-12	**13**	9.34e-15	**14**	1.30e-15	**2**	9.46e-16	**2**
Difluoro(methoxy)methane	CH_3OCHF_2	1.1	0.17[g]	1.32e-11	**528**	1.32e-11	**144**	1.18e-13	**173**	1.52e-14	**25**	1.08e-14	**20**
Fluoro(fluoromethoxy)methane	CH_2FOCH_2F	0.9	0.19[g]	1.20e-11	**479**	1.20e-11	**130**	1.05e-13	**153**	1.37e-14	**22**	9.84e-15	**18**
Difluoro(fluoromethoxy)methane	CH_2FOCHF_2	3.3	0.30[g]	5.65e-11	**2260**	5.66e-11	**617**	6.88e-13	**1010**	7.11e-14	**115**	4.69e-14	**86**
Trifluoro(fluoromethoxy)methane	CH_2FOCF_3	4.4	0.33[g]	6.82e-11	**2730**	6.89e-11	**751**	9.59e-13	**1400**	9.27e-14	**150**	5.72e-14	**105**
HG′-01	$CH_3OCF_2CF_2OCH_3$	2.0	0.29	2.03e-11	**815**	2.03e-11	**222**	2.06e-13	**301**	2.42e-14	**39**	1.68e-14	**31**
HG′-02	$CH_3O(CF_2CF_2O)_2CH_3$	2.0	0.56	2.16e-11	**868**	2.16e-11	**236**	2.19e-13	**320**	2.57e-14	**42**	1.79e-14	**33**
HG′-03	$CH_3O(CF_2CF_2O)_3CH_3$	2.0	0.76	2.03e-11	**812**	2.03e-11	**221**	2.05e-13	**299**	2.41e-14	**39**	1.67e-14	**31**
HFE-329me3	$CF_3CFHCF_2OCF_3$	40.0	0.48	1.79e-10	**7170**	4.17e-10	**4550**	4.85e-12	**7090**	2.89e-12	**4690**	1.12e-12	**2040**
3,3,4,4,5,5,6,6,7,7,7-Undecafluoroheptan-1-ol	$CF_3(CF_2)_4CH_2CH_2OH$	20.0 days	0.06	3.91e-14	**2**	3.91e-14	**<1**	3.12e-16	**<1**	4.39e-17	**<1**	3.21e-17	**<1**
3,3,4,4,5,5,6,6,7,7,8,8,9,9,9-Pentadecafluorononan-1-ol	$CF_3(CF_2)_6CH_2CH_2OH$	20.0 days	0.07	3.00e-14	**1**	3.00e-14	**<1**	2.40e-16	**<1**	3.37e-17	**<1**	2.46e-17	**<1**
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,11,11,11-Nonadecafluoroundecan-1-ol	$CF_3(CF_2)_8CH_2CH_2OH$	20.0 days	0.05	1.72e-14	**<1**	1.72e-14	**<1**	1.37e-16	**<1**	1.93e-17	**<1**	1.41e-17	**<1**
2-Chloro-1,1,2-trifluoro-1-methoxyethane	CH_3OCF_2CHFCl	1.4	0.21	1.12e-11	**449**	1.12e-11	**122**	1.05e-13	**153**	1.31e-14	**21**	9.24e-15	**17**
PFPMIE (perfluoropolymethylisopropyl ether)	$CF_3OCF(CF_3)$ $CF_2OCF_2OCF_3$	800.0	0.65	1.87e-10	**7500**	8.90e-10	**9710**	5.52e-12	**8070**	6.11e-12	**9910**	6.15e-12	**11,300**
HFE-216	$CF_3OCF{=}CF_2$	8.4 days	0.02	1.92e-14	**<1**	1.92e-14	**<1**	1.53e-16	**<1**	2.15e-17	**<1**	1.58e-17	**<1**
Trifluoromethyl formate	$HCOOCF_3$	3.5	0.31[i]	5.37e-11	**2150**	5.39e-11	**588**	6.73e-13	**984**	6.85e-14	**111**	4.47e-14	**82**
Perfluoroethyl formate	$HCOOCF_2CF_3$	3.5	0.44[i]	5.30e-11	**2130**	5.32e-11	**580**	6.64e-13	**971**	6.76e-14	**110**	4.41e-14	**81**
Perfluoropropyl formate	$HCOOCF_2CF_2CF_3$	2.6	0.50[i]	3.45e-11	**1380**	3.45e-11	**376**	3.80e-13	**555**	4.19e-14	**68**	2.85e-14	**52**
Perfluorobutyl formate	$HCOOCF_2CF_2CF_2CF_3$	3.0	0.56[i]	3.59e-11	**1440**	3.59e-11	**392**	4.19e-13	**613**	4.45e-14	**72**	2.97e-14	**54**
2,2,2-Trifluoroethyl formate	$HCOOCH_2CF_3$	0.4	0.16[i]	3.07e-12	**123**	3.07e-12	**33**	2.55e-14	**37**	3.48e-15	**6**	2.52e-15	**5**
3,3,3-Trifluoropropyl formate	$HCOOCH_2CH_2CF_3$	0.3	0.13[i]	1.60e-12	**64**	1.60e-12	**17**	1.31e-14	**19**	1.80e-15	**3**	1.31e-15	**2**
1,2,2,2-Tetrafluoroethyl formate	$HCOOCHFCF_3$	3.2	0.35[i]	4.30e-11	**1720**	4.31e-11	**470**	5.17e-13	**755**	5.39e-14	**87**	3.57e-14	**65**
1,1,1,3,3,3-Hexafluoropropan-2-yl formate	$HCOOCH(CF_3)_2$	3.2	0.33[i]	3.05e-11	**1220**	3.05e-11	**333**	3.66e-13	**535**	3.81e-14	**62**	2.53e-14	**46**
Perfluorobutyl acetate	$CH_3COOCF_2CF_2CF_2CF_3$	21.9 days	0.12[i]	1.52e-13	**6**	1.52e-13	**2**	1.21e-15	**2**	1.71e-16	**<1**	1.25e-16	**<1**
Perfluoropropyl acetate	$CH_3COOCF_2CF_2CF_3$	21.9 days	0.11[i]	1.59e-13	**6**	1.59e-13	**2**	1.27e-15	**2**	1.78e-16	**<1**	1.30e-16	**<1**
Perfluoroethyl acetate	$CH_3COOCF_2CF_3$	21.9 days	0.10[i]	1.89e-13	**8**	1.89e-13	**2**	1.51e-15	**2**	2.12e-16	**<1**	1.55e-16	**<1**
Trifluoromethyl acetate	CH_3COOCF_3	21.9 days	0.07[i]	1.90e-13	**8**	1.90e-13	**2**	1.52e-15	**2**	2.14e-16	**<1**	1.56e-16	**<1**

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Table 8.A.1 (continued)

Acronym, Common Name or Chemical Name	Chemical Formula	Lifetime (Years)	Radiative Efficiency ($W\ m^{-2}\ ppb^{-1}$)	AGWP 20-year ($W\ m^{-2}\ yr\ kg^{-1}$)	**GWP 20-year**	AGWP 100-year ($W\ m^{-2}\ yr\ kg^{-1}$)	**GWP 100-year**	AGTP 20-year ($K\ kg^{-1}$)	**GTP 20-year**	AGTP 50-year ($K\ kg^{-1}$)	**GTP 50-year**	AGTP 100-year ($K\ kg^{-1}$)	**GTP 100-year**
Methyl carbonofluoridate	$FCOOCH_3$	1.8	0.07^i	8.74e-12	**350**	8.74e-12	**95**	8.60e-14	**126**	1.03e-14	**17**	7.21e-15	**13**
1,1-Difluoroethyl carbonofluoridate	$FCOOCF_2CH_3$	0.3	0.17^i	2.46e-12	**99**	2.46e-12	**27**	2.02e-14	**30**	2.78e-15	**5**	2.02e-15	**4**
1,1-Difluoroethyl 2,2,2-trifluoroacetate	$CF_3COOCF_2CH_3$	0.3	0.27^i	2.83e-12	**113**	2.83e-12	**31**	2.33e-14	**34**	3.20e-15	**5**	2.32e-15	**4**
Ethyl 2,2,2-trifluoroacetate	$CF_3COOCH_2CH_3$	21.9 days	0.05^i	1.26e-13	**5**	1.26e-13	**1**	1.00e-15	**1**	1.41e-16	**<1**	1.03e-16	**<1**
2,2,2-Trifluoroethyl 2,2,2-trifluoroacetate	$CF_3COOCH_2CF_3$	54.8 days	0.15^i	6.27e-13	**25**	6.27e-13	**7**	5.06e-15	**7**	7.07e-16	**1**	5.15e-16	**<1**
Methyl 2,2,2-trifluoroacetate	CF_3COOCH_3	0.6	0.18^i	4.80e-12	**192**	4.80e-12	**52**	4.08e-14	**60**	5.47e-15	**9**	3.95e-15	**7**
Methyl 2,2-difluoroacetate	HCF_2COOCH_3	40.1 days	0.05^i	3.00e-13	**12**	3.00e-13	**3**	2.41e-15	**4**	3.38e-16	**<1**	2.47e-16	**<1**
Difluoromethyl 2,2,2-trifluoroacetate	$CF_3COOCHF_2$	0.3	0.24^i	2.48e-12	**99**	2.48e-12	**27**	2.04e-14	**30**	2.81e-15	**5**	2.04e-15	**4**
2,2,3,3,4,4,4-Heptafluorobutan-1-ol	$C_3F_7CH_2OH$	0.6	0.20	3.10e-12	**124**	3.10e-12	**34**	2.61e-14	**38**	3.52e-15	**6**	2.55e-15	**5**
1,1,2-Trifluoro-2-(trifluoromethoxy)-ethane	$CHF_2CHFOCF_3$	9.8	0.35	9.91e-11	**3970**	1.14e-10	**1240**	2.03e-12	**2960**	2.88e-13	**467**	9.74e-14	**178**
1-Ethoxy-1,1,2,3,3,3-hexafluoropropane	$CF_3CHFCF_2OCH_2CH_3$	0.4	0.19	2.14e-12	**86**	2.14e-12	**23**	1.77e-14	**26**	2.43e-15	**4**	1.76e-15	**3**
1,1,1,2,2,3,3-Heptafluoro-3-(1,2,2,2-tetrafluoroethoxy)-propane	$CF_3CF_2CF_2OCHFCF_3$	67.0	0.58	1.98e-10	**7940**	5.95e-10	**6490**	5.57e-12	**8140**	4.29e-12	**6960**	2.39e-12	**4380**
2,2,3,3-Tetrafluoro-1-propanol	$CHF_2CF_2CH_2OH$	91.3 days	0.11	1.19e-12	**48**	1.19e-12	**13**	9.72e-15	**14**	1.35e-15	**2**	9.79e-16	**2**
2,2,3,4,4,4-Hexafluoro-1-butanol	$CF_3CHFCF_2CH_2OH$	94.9 days	0.19	1.56e-12	**63**	1.56e-12	**17**	1.27e-14	**19**	1.76e-15	**3**	1.28e-15	**2**
2,2,3,3,4,4,4-Heptafluoro-1-butanol	$CF_3CF_2CF_2CH_2OH$	0.3	0.16	1.49e-12	**60**	1.49e-12	**16**	1.23e-14	**18**	1.69e-15	**3**	1.23e-15	**2**
1,1,2,2-Tetrafluoro-3-methoxy-propane	$CHF_2CF_2CH_2OCH_3$	14.2 days	0.03	4.82e-14	**2**	4.82e-14	**<1**	3.84e-16	**<1**	5.41e-17	**<1**	3.96e-17	**<1**
perfluoro-2-methyl-3-pentanone	$CF_3CF_2C(O)CF(CF_3)_2$	7.0 days	0.03	9.14e-15	**<1**	9.14e-15	**<1**	7.27e-17	**<1**	1.03e-17	**<1**	7.51e-18	**<1**
3,3,3-Trifluoro-propanal	CF_3CH_2CHO	2.0 days	0.004	9.86e-16	**<1**	9.86e-16	**<1**	7.84e-18	**<1**	1.11e-18	**<1**	8.10e-19	**<1**
2-Fluoroethanol	CH_2FCH_2OH	20.4 days	0.02	8.07e-14	**3**	8.07e-14	**<1**	6.45e-16	**<1**	9.07e-17	**<1**	6.63e-17	**<1**
2,2-Difluoroethanol	CHF_2CH_2OH	40.0 days	0.04	2.78e-13	**11**	2.78e-13	**3**	2.23e-15	**3**	3.12e-16	**<1**	2.28e-16	**<1**
2,2,2-Trifluoroethanol	CF_3CH_2OH	0.3	0.10	1.83e-12	**73**	1.83e-12	**20**	1.50e-14	**22**	2.07e-15	**3**	1.50e-15	**3**
1,1'-Oxybis[2-(difluoromethoxy)-1,1,2,2-tetrafluoroethane	$HCF_2O(CF_2CF_2O)_2CF_2H$	26.0	1.15^k	2.47e-10	**9910**	4.51e-10	**4920**	6.38e-12	**9320**	2.75e-12	**4460**	7.45e-13	**1360**
1,1,3,3,4,4,6,6,7,7,9,9,10,10,12,12-hexadecafluoro-2,5,8,11-Tetraoxadodecane	$HCF_2O(CF_2CF_2O)_3CF_2H$	26.0	1.43^k	2.26e-10	**9050**	4.12e-10	**4490**	5.83e-12	**8520**	2.51e-12	**4080**	6.81e-13	**1250**
1,1,3,3,4,4,6,6,7,7,9,9,10,10,12,12,13,13,15,15-eicosafluoro-2,5,8,11,14-Pentaoxapentadecane	$HCF_2O(CF_2CF_2O)_4CF_2H$	26.0	1.46^k	1.83e-10	**7320**	3.33e-10	**3630**	4.71e-12	**6880**	2.03e-12	**3300**	5.50e-13	**1010**

Notes:

For CH_4 we estimate an uncertainty of ±30% and ±40% for 20- and 100-year time horizon, respectively (for 90% uncertainty range). The uncertainty is dominated by AGWP for CO_2 and indirect effects. The uncertainty in GWP for N_2O is estimated to ±20% and ±30% for 20- and 100-year time horizon, with the largest contributions from CO_2. The uncertainty in GWP for HFC-134a is estimated to ±25% and ±35% for 20- and 100-year time horizons while for CFC-11 the GWP the corresponding numbers are approximately ±20% and ±35% (not accounting for the indirect effects). For CFC-12 the corresponding numbers are ±20 and ±30. The uncertainties estimated for HFC-134a and CFC-11 are assessed as representative for most other gases with similar or longer lifetimes. For shorter-lived gases, the uncertainties will be larger. For GTP, few estimates are available in the literature. The uncertainty is assessed to be of the order of ±75% for the methane GTP_{100}.

* No single lifetime can be given. The impulse response function for CO_2 from Joos et al. (2013) has been used. See also Supplementary Material Section 8.SM.11.

† Perturbation lifetime is used in calculation of metrics, not the lifetime of the atmospheric burden.

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Table 8.A.1 Notes (continued)

‡ Metric values for CH_4 of fossil origin include the oxidation to CO_2 (based on Boucher et al., 2009). In applications of these values, inclusion of the CO_2 effect of fossil methane must be done with caution to avoid any double-counting because CO_2 emissions numbers are often based on total carbon content. Methane values without the CO_2 effect from fossil methane are thus appropriate for fossil methane sources for which the carbon has been accounted for elsewhere, or for biospheric methane sources for which there is abalance between CO_2 taken up by the biosphere and CO_2 produced from CH_4 oxidization. The addition effect on GWP and GTP represents lower limits from Boucher et al. (2009) and assume 50% of the carbon is deposited as formaldehyde to the surface and is then lost. The upper limit in Boucher et al. (2009) made the assumption that this deposited formaldehyde was subsequently further oxidized to CO_2 .

[a] RE is unchanged since AR4.

[b] RE is unchanged since AR4 except the absolute forcing is increased by a factor of 1.04 to account for the change in the recommended RE of CFC-11.

[c] Based on Rajakumar et al. (2006) (lifetime correction factor has been applied to account for non-homogeneous horizontal and vertical mixing).

[d] Based on instantaneous RE from Baasandorj et al. (2010); Baasandorj et al. (2011) (correction factors have been applied to account for stratospheric temperature adjustment and non-homogeneous horizontal and vertical mixing).

[e] Based on instantaneous RE from *ab initio* study of Bravo et al. (2010) (a factor 1.10 has been applied to account for stratospheric temperature adjustment).

[f] Based on average instantaneous RE reported in literature (Vasekova et al., 2006; Bravo et al., 2010) (correction factors have been applied to account for stratospheric temperature adjustment and non-homogeneous horizontal and vertical mixing).

[g] Based on instantaneous RE from *ab initio* studies of Blowers et al. (2007, 2008)(correction factors have been applied to account for stratospheric temperature adjustment and non-homogeneous horizontal and vertical mixing).

[h] Based on instantaneous RE from Heathfield et al. (1998) (correction factors have been applied to account for stratospheric temperature adjustment and non-homogeneous horizontal and vertical mixing).

[i] Note that calculation of RE is based on calculated (*ab initio*) absorption cross-section and uncertainties are therefore larger than for calculations using experimental absorption cross section.

[j] Based on instantaneous RE from Javadi et al. (2007) (correction factors have been applied to account for stratospheric temperature adjustment and non-homogeneous horizontal and vertical mixing).

[k] Based on instantaneous RE from Andersen et al. (2010) (correction factors have been applied to account for stratospheric temperature adjustment and non-homogeneous horizontal and vertical mixing).

The GTP values are calculated with a temperature impulse response function taken from Boucher and Reddy (2008). See also Supplementary Material Section 8.SM.11.

Table 8.A.2 | Halocarbon indirect GWPs from ozone depletion using the EESC-based method described in WMO (2011), adapted from Daniel et al. (1995). A radiative forcing in year 2011 of –0.15 (–0.30 to 0.0) W m^{-2} relative to preindustrial times is used (see Section 8.3.3). Uncertainty on the indirect AGWPs due to the ozone forcing uncertainty is ±100%.

Gas	GWP_{100}
CFC-11	–2640
CFC-12	–2100
CFC-113	–2150
CFC-114	–914
CFC-115	–223
HCFC-22	–98
HCFC-123	–37
HCFC-124	–46
HCFC-141b	–261
HCFC-142b	–152
CH_3CCl_3	–319
CCl_4	–2110
CH_3Br	–1250
Halon-1211	–19,000
Halon-1301	–44,500
Halon-2402	–32,000
HCFC-225ca	–40
HCFC-225cb	–60

Table 8.A.3 | GWP and GTP for NO_X from surface sources for time horizons of 20 and 100 years from the literature. All values are on a per kilogram of nitrogen basis. Uncertainty for numbers from Fry et al. (2012) and Collins et al. (2013) refer to 1-σ. For the reference gas CO_2, RE and IRF from AR4 are used in the calculations. The GWP_{100} and GTP_{100} values can be scaled by 0.94 and 0.92, respectively, to account for updated values for the reference gas CO_2. For 20 years the changes are negligible.

	GWP		GTP	
	H = 20	H = 100	H = 20	H = 100
NO_X East Asia[a]	6.4 (±38.1)	–5.3 (±11.5)	–55.6 (±23.8)	–1.3 (±2.1)
NO_X EU + North Africa[a]	–39.4 (±17.5)	–15.6 (±5.8)	–48.0 (±14.9)	–2.5 (±1.3)
NO_X North America[a]	–2.4 (±30.3)	–8.2 (±10.3)	–61.9 (±27.8)	–1.7 (±2.1)
NO_X South Asia[a]	–40.7 (±88.3)	–25.3 (±29.0)	–124.6 (±67.4)	–4.6 (±5.1)
NO_X four above regions[a]	–15.9 (±32.7)	–11.6 (±10.7)	–62.1 (±26.2)	–2.2 (±2.1)
Mid-latitude NOx[c]	–43 to +23	–18 to +1.6	–55 to –37	–2.9 to –0.02
Tropical NO_x[c]	43 to 130	–28 to –10	–260 to –220	–6.6 to –5.4
NO_X global[b]	19	–11	–87	–2.9
NO_X global[d]	–108 ± 35 –335 ± 110 –560 ± 279	–31 ± 10 –95 ± 31 –159 ± 79		

Notes:

[a] Fry et al. (2012) (updated by including stratospheric H_2O) and Collins et al. (2013).

[b] Fuglestvedt et al. (2010); based on Wild et al. (2001).

[c] Fuglestvedt et al. (2010).

[d] Shindell et al. (2009). Three values are given: First, without aerosols, second, direct aerosol effect included (sulfate and nitrate), third, direct and indirect aerosol effects included. Uncertainty ranges from Shindell et al. (2009) are given for 95% confidence levels.

Table 8.A.4 | GWP and GTP for CO for time horizons of 20 and 100 years from the literature. Uncertainty for numbers from Fry et al. (2012) and Collins et al. (2013) refer to 1-σ. For the reference gas CO_2, RE and IRF from AR4 are used in the calculations. The GWP_{100} and GTP_{100} values can be scaled by 0.94 and 0.92, respectively, to account for updated values for the reference gas CO_2. For 20 years the changes are negligible.

	GWP		GTP	
	H = 20	H = 100	H = 20	H = 100
CO East Asia[a]	5.4 (±1.7)	1.8 (±0.6)	3.5 (±1.3)	0.26 (±0.12)
CO EU + North Africa[a]	4.9 (±1.5)	1.6 (±0.5)	3.2 (±1.2)	0.24 (±0.11)
CO North America[a]	5.6 (±1.8)	1.8 (±0.6)	3.7 (±1.3)	0.27 (±0.12)
CO South Asia[a]	5.7 (±1.3)	1.8 (±0.4)	3.4 (±1.0)	0.27 (±0.10)
CO four regions above[a]	5.4 (±1.6)	1.8 (±0.5)	3.5 (±1.2)	0.26 (±0.11)
CO global[b]	6 to 9.3	2 to 3.3	3.7 to 6.1	0.29 to 0.55
CO global[c]	7.8 ± 2.0 11.4 ± 2.9 18.6 ± 8.3	2.2 ± 0.6 3.3 ± 0.8 5.3 ± 2.3		

Notes:

[a] Fry et al. (2012) (updated by including stratospheric H_2O) and Collins et al. (2013).

[b] Fuglestvedt et al. (2010).

[c] Shindell et al. (2009). Three values are given: First, without aerosols, second, direct aerosol effect included, third, direct and indirect aerosol effects included. Uncertainty ranges from Shindell et al. (2009) are given for 95% confidence levels.

Table 8.A.5 | GWP and GTP for VOCs for time horizons of 20 and 100 years from the literature. Uncertainty for numbers from Fry et al. (2012) and Collins et al. (2013) refer to 1-σ. For the reference gas CO_2, RE and IRF from AR4 are used in the calculations. The GWP_{100} and GTP_{100} values can be scaled by 0.94 and 0.92, respectively, to account for updated values for the reference gas CO_2. For 20 years the changes are negligible.

	GWP		GTP	
	H = 20	H = 100	H = 20	H = 100
VOC East Asia[a]	16.3 (±6.4)	5.0 (±2.1)	8.4 (±4.6)	0.7 (±0.4)
VOC EU + North Africa[a]	18.0 (±8.5)	5.6 (±2.8)	9.5 (±6.5)	0.8 (±0.5)
VOC North America[a]	16.2 (±9.2)	5.0 (±3.0)	8.6 (±6.4)	0.7 (±0.5)
VOC South Asia[a]	27.8 (±5.6)	8.8 (±1.9)	15.7 (±5.0)	1.3 (±0.5)
VOC four regions above	18.7 (±7.5)	5.8 (±2.5)	10.0 (±5.7)	0.9 (±0.5)
VOC global[b]	14	4.5	7.5	0.66

Notes:

[a] Fry et al. (2012) (updated by including stratospheric H_2O) and Collins et al. (2013).

[b] Fuglestvedt et al. (2010) based on Collins et al. (2002).

The values are given on a per kilogram of C basis.

Table 8.A.6 | GWP and GTP from the literature for BC and OC for time horizons of 20 and 100 years. For the reference gas CO_2, RE and IRF from AR4 are used in the calculations. The GWP_{100} and GTP_{100} values can be scaled by 0.94 and 0.92, respectively, to account for updated values for the reference gas CO_2. For 20 years the changes are negligible.

	GWP		GTP	
	H = 20	H = 100	H = 20	H = 100
BC total, global[c]	3200 (270 to 6200)	900 (100 to 1700)	920 (95 to 2400)	130 (5 to 340)
BC (four regions)[d]	1200 ± 720	345 ± 207	420 ± 190	56 ± 25
BC global[a]	1600	460	470	64
BC aerosol–radiation interaction +albedo, global[b]	2900 ± 1500	830 ± 440		
OC global[a]	–240	–69	–71	–10
OC global[b]	–160 (–60 to –320)	–46 (–18 to –19)		
OC (4 regions)[d]	–160 ± 68	–46 ± 20	–55 ± 16	–7.3±2.1

Notes:

[a] Fuglestvedt et al. (2010).

[b] Bond et al. (2011). Uncertainties for OC are asymmetric and are presented as ranges.

[c] Bond et al. (2013). Metric values are given for total effect.

[d] Collins et al. (2013). The four regions are East Asia, EU + North Africa, North America and South Asia (as also given in Fry et al., 2012). Only aerosol-radiation interaction is included.

EPA 430-R-11-005

INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS:

1990 – 2009

APRIL 15, 2011

U.S. Environmental Protection Agency
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All data tables of this document are available for the full time series 1990 through 2009, inclusive, at the internet site mentioned above.

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For more information regarding climate change and greenhouse gas emissions, see the EPA web site at <http://www.epa.gov/climatechange>.

Released for printing: April 15, 2011

Acknowledgments

The Environmental Protection Agency would like to acknowledge the many individual and organizational contributors to this document, without whose efforts this report would not be complete. Although the complete list of researchers, government employees, and consultants who have provided technical and editorial support is too long to list here, EPA's Office of Atmospheric Programs would like to thank some key contributors and reviewers whose work has significantly improved this year's report.

Work on emissions from fuel combustion was led by Leif Hockstad and Brian Cook. Ed Coe directed the work on mobile combustion and transportation. Work on industrial process emissions was led by Mausami Desai. Work on methane emissions from the energy sector was directed by Lisa Hanle and Kitty Sibold. Calculations for the waste sector were led by Rachel Schmeltz. Tom Wirth directed work on the Agriculture, and together with Jennifer Jenkins, directed work on the Land Use, Land-Use Change, and Forestry chapters. Work on emissions of HFCs, PFCs, and SF_6 was directed by Deborah Ottinger and Dave Godwin.

Within the EPA, other Offices also contributed data, analysis, and technical review for this report. The Office of Transportation and Air Quality and the Office of Air Quality Planning and Standards provided analysis and review for several of the source categories addressed in this report. The Office of Solid Waste and the Office of Research and Development also contributed analysis and research.

The Energy Information Administration and the Department of Energy contributed invaluable data and analysis on numerous energy-related topics. The U.S. Forest Service prepared the forest carbon inventory, and the Department of Agriculture's Agricultural Research Service and the Natural Resource Ecology Laboratory at Colorado State University contributed leading research on nitrous oxide and carbon fluxes from soils.

Other government agencies have contributed data as well, including the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, the Federal Aviation Administration, and the Department of Defense.

We would also like to thank Marian Martin Van Pelt, Randy Freed, and their staff at ICF International's Energy, Environment, and Transportation Practice, including Don Robinson, Diana Pape, Susan Asam, Michael Grant, Robert Lanza, Chris Steuer, Toby Mandel, Lauren Pederson, Joseph Herr, Jeremy Scharfenberg, Mollie Averyt, Ashley Labrie, Hemant Mallya, Sandy Seastream, Douglas Sechler, Ashaya Basnyat, Kristen Schell, Victoria Thompson, Mark Flugge, Paul Stewart, Tristan Kessler, Katrin Moffroid, Veronica Kennedy, Kaye Schultz, Seth Greenburg, Larry O'Rourke, Rubab Bhangu, Deborah Harris, Emily Rowan, Roshni Rathi, Lauren Smith, Nikhil Nadkarni, Caroline Cochran, Joseph Indvik, Aaron Sobel, and Neha Mukhi for synthesizing this report and preparing many of the individual analyses. Eastern Research Group, RTI International, Raven Ridge Resources, and Ruby Canyon Engineering Inc. also provided significant analytical support.

Preface

The United States Environmental Protection Agency (EPA) prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC). Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15.

In an effort to engage the public and researchers across the country, the EPA has instituted an annual public review and comment process for this document. The availability of the draft document is announced via Federal Register Notice and is posted on the EPA web site. Copies are also mailed upon request. The public comment period is generally limited to 30 days; however, comments received after the closure of the public comment period are accepted and considered for the next edition of this annual report.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2009. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports

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[1] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[7] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2005, concentrations of these greenhouse gases have increased globally by 36, 148, and 18 percent, respectively (IPCC 2007).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[8]   The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

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[7] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

[8] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[9,10] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[11] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2009 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO_2 Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly. Since 1990, U.S. emissions have increased at an average annual rate of 0.4 percent.

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[9] Carbon comprises 12/44^{ths} of carbon dioxide by weight.

[10] One teragram is equal to 10^{12} grams or one million metric tons.

[11] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2009.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq. or million metric tons CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*

Change, and Forestry (Sink)[a]							
Biomass - Wood[b]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[b]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0

HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2009. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.0 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have increased by 1.7 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management and mobile source fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted as a by-product of primary aluminum production and from semiconductor manufacturing, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively. Conversely, N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). From 1990 to 2009, HFCs increased by 88.8 Tg CO_2 Eq. (240.41 percent), PFCs decreased by 15.1 Tg CO_2 Eq. (73.0 percent), and SF_6 decreased by 19.5 Tg CO_2 Eq. (56.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.3 percent of total emissions in 2009. The following sections describe each gas' contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 36 percent (IPCC 2007), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 94.6 percent of CO_2 emissions in 2009. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[12] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2009 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2009. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 20 years, and (2) overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2009, CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease in any year over the twenty-year period.

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

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[12] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories[a]	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 33 percent of CO_2 emissions from fossil fuel combustion in 2009.[13] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2009, transportation emissions rose by 16 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2009. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2009. Both sectors relied heavily on electricity for meeting energy demands, with 70 and 77 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 25 percent since 1990, due to increasing electricity consumption for lighting, heating, air

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[13] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 35 percent of U.S. emissions from fossil fuel combustion in 2009.

conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 41 percent of the CO_2 from fossil fuel combustion in 2009. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 95 percent of all coal consumed for energy in the United States in 2009. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production decreased by 24.1 Tg CO_2 Eq. (36.6 percent) from 2008 to 2009, continuing a trend of decreasing emissions from 1990 through 2009 of 57.9 percent (57.7 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2009, CO_2 emissions from cement production decreased by 11.5 Tg CO_2 Eq. (28.4 percent) from 2008. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the last three years. Overall, from 1990 to 2009, emissions from cement production decreased by 12.8 percent, a decrease of 4.3 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 153.5 Tg CO_2 Eq. (17.8 percent) from 1990 through 2009. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 148 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, , agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2009 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- In 2009, CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq., a 3.9 Tg CO_2 Eq. (5.8 percent) increase over 2008 emission levels. The overall decline of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2009 with 221.2 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990. Methane emissions from this source increased 4 percent from 2008 to 2009 due to an increase in production and production wells.
- Enteric Fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2009, enteric fermentation CH_4 emissions were 139.8 Tg CO_2 Eq. (20 percent of total CH_4 emissions), which represents an increase of 7.7 Tg CO_2 Eq. (5.8 percent) since 1990.

- Methane emissions from manure management increased by 55.9 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 17 percent of total CH_4 emissions (117.5 Tg CO_2 Eq.) in 2009. From 1990 to 2009, CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[14] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 18 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, manure management, nitric acid production and stationary fuel combustion, (see Figure ES-9).

Figure ES-9: 2009 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly since 1996 from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990, and emissions from adipic acid production have remained consistently lower than pre-1996 levels since 1998.
- Agricultural soils accounted for approximately 69.2 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the

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[14] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-outs required under the Montreal Protocol come into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 85.2 percent (31.0 Tg CO_2 Eq.) from 1990 through 2009, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 54.8 percent (15.6 Tg CO_2 Eq.) from 1990 to 2009, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (9 percent), and 35.7 Tg CO_2 Eq. (9 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10 percent), 24.7 Tg CO_2 Eq. (14 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 143.5 Tg CO_2 Eq. (17 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

Use Change, and Forestry (Sinks)*							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87 percent of total U.S. greenhouse gas emissions in 2009.

Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4 percent of U.S. greenhouse gas emissions in 2009.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2009.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2009, accounting for 69 percent. In 2009, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest Land Remaining Forest Land[1]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. The application of crushed limestone and dolomite to managed land (i.e., liming of agricultural soils) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of 11 percent relative to 1990. The application of synthetic fertilizers to forest and settlement soils in 2009 resulted in direct N_2O emissions of 1.9 Tg CO_2 Eq. Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils increased by 55 percent since 1990. Forest fires resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. in 2009. CO_2 and N_2O emissions from peatlands totaled 1.1 Tg CO_2 Eq. and less than 0.01 Tg CO_2 Eq. in 2009, respectively.

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6

Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for just over 78 percent of this chapter's emissions, and 17 percent of total U.S. CH_4 emissions.[15] Additionally, wastewater treatment accounts for 20 percent of Waste emissions, 4 percent of U.S. CH_4 emissions, and 2 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.7 Tg CO_2 Eq. and 1.8 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.3 percent of total U.S. greenhouse gas emissions in 2009.

Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2009.

Figure ES-13: Emissions Allocated to Economic Sectors

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5

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[15] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial sector accounted for 6 percent of emissions while the residential sector accounted for 5 percent of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[16] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, Industrial activities account for the largest share of U.S. greenhouse gas emissions (29 percent) in 2009. Transportation is the second largest contributor to total U.S. emissions (28 percent). The commercial and residential sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2009. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2009.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Land Use, Land-Use Change,	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

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[16] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

and Forestry (Sinks)							
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**	**Growth Rate[a]**
GDP[b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption[c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100	117	119	117	119	116	108	0.5%
Energy Consumption[c]	100	116	118	118	120	118	112	0.6%
Population[d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate

[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)

[c] Energy content-weighted values (EIA 2010b)

[d] U.S. Census Bureau (2010)

[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[17] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[18] which are regulated under the Clean Air Act. Table ES- 10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES- 10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0

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[17] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[18] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[19] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2009 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2009 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

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[19] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

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Box ES-3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors." In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2009) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

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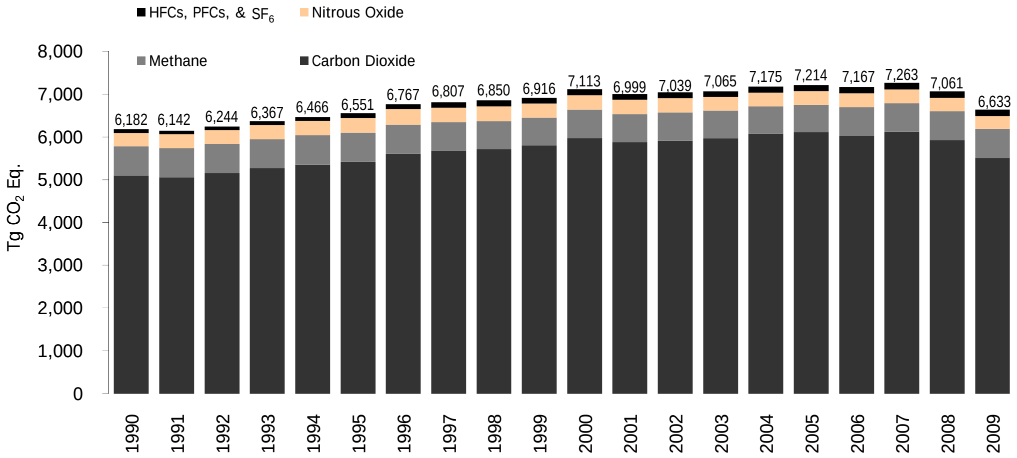


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

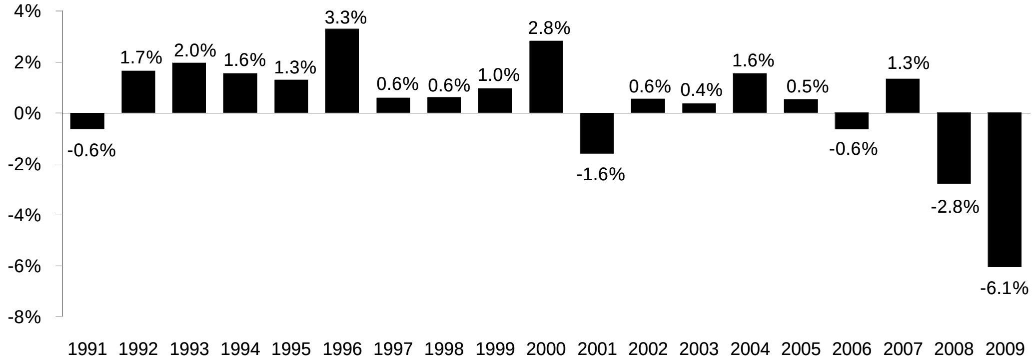


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

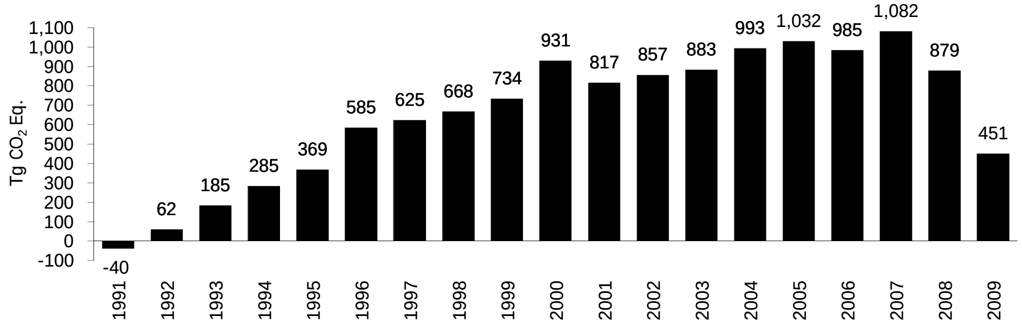


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

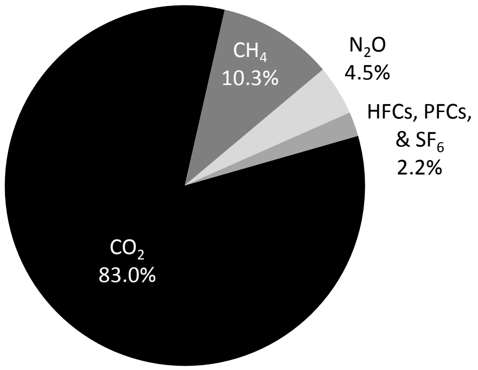


Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

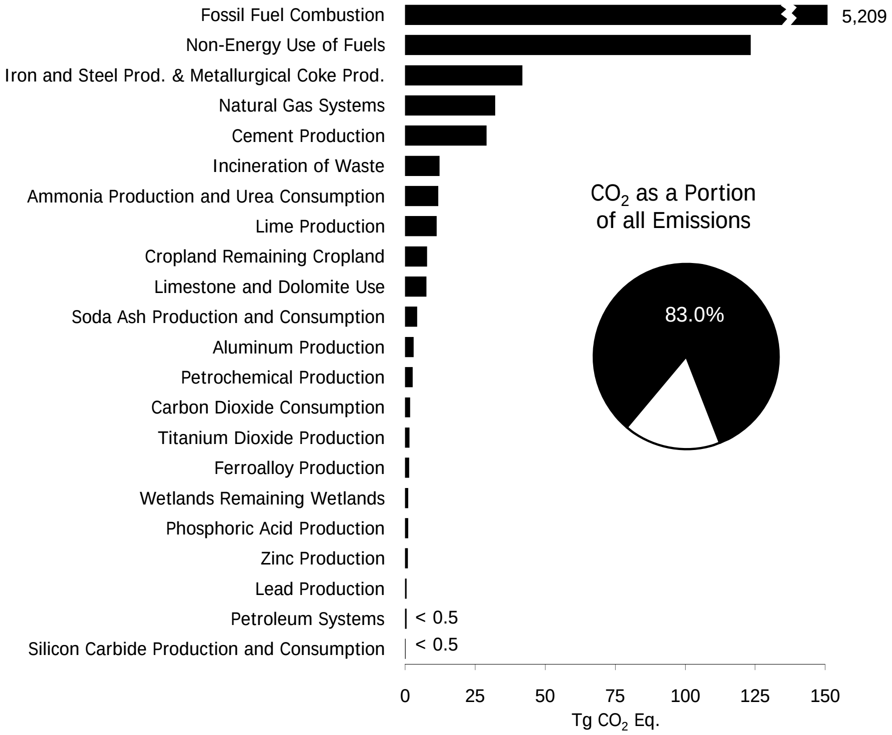


Figure ES-5: 2009 Sources of CO_2 Emissions

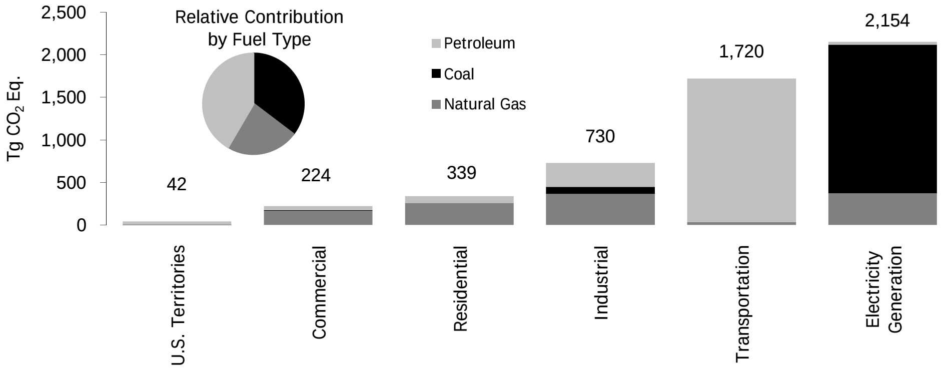


Figure ES-6: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

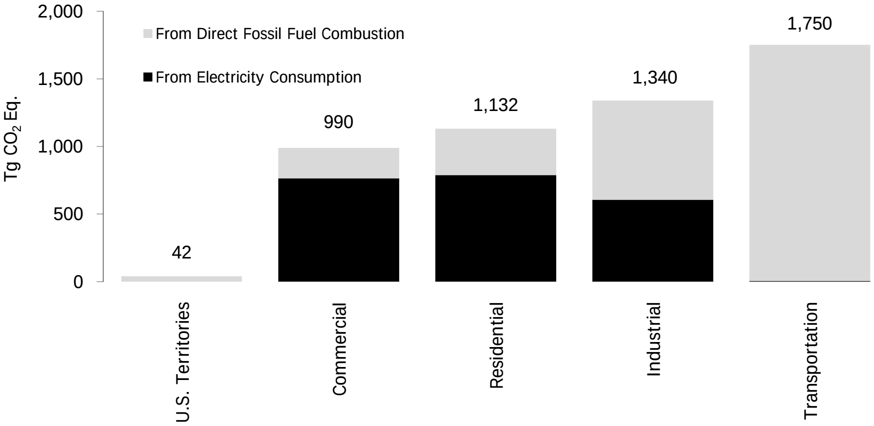


Figure ES-7: 2009 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

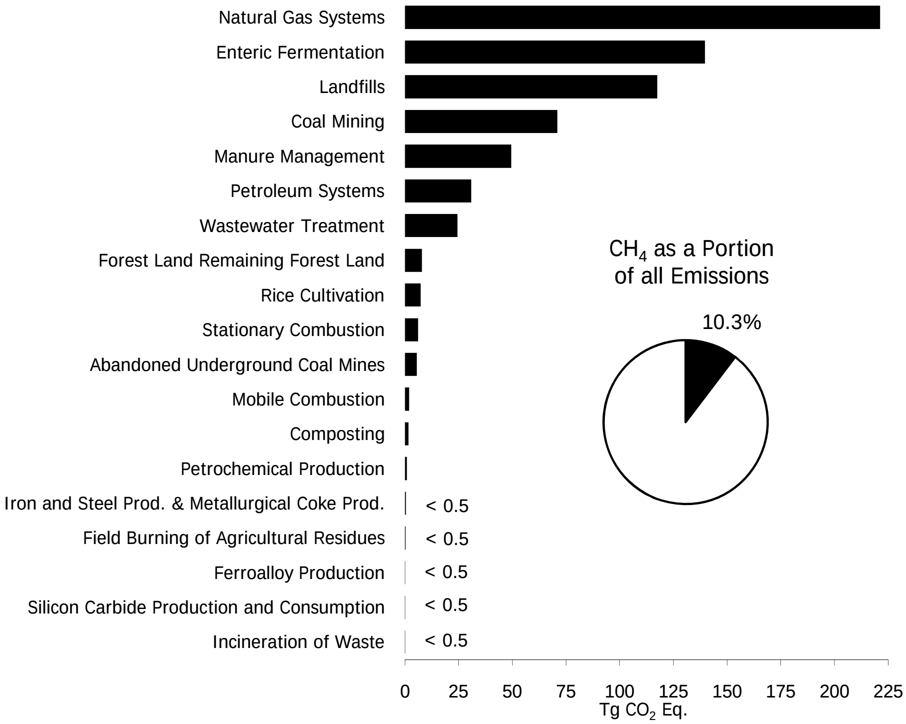


Figure ES-8: 2009 Sources of CH_4 Emissions

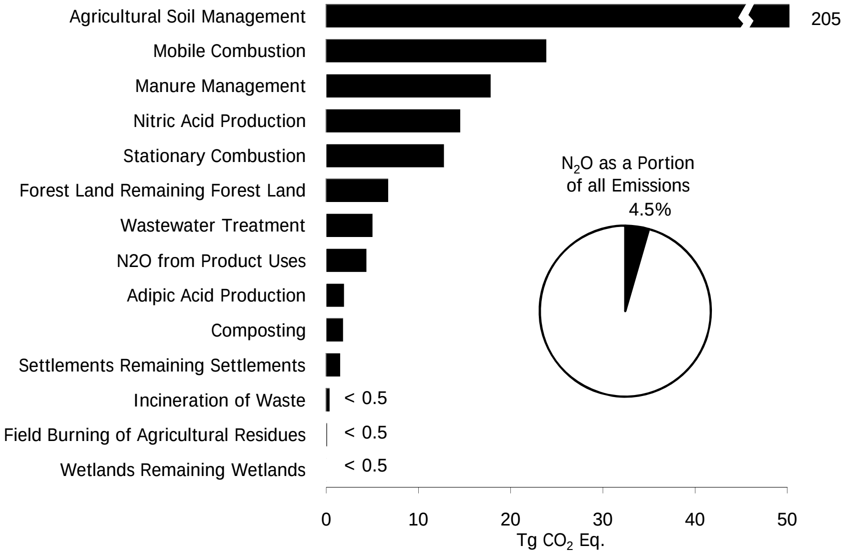


Figure ES-9: 2009 Sources of N_2O Emissions

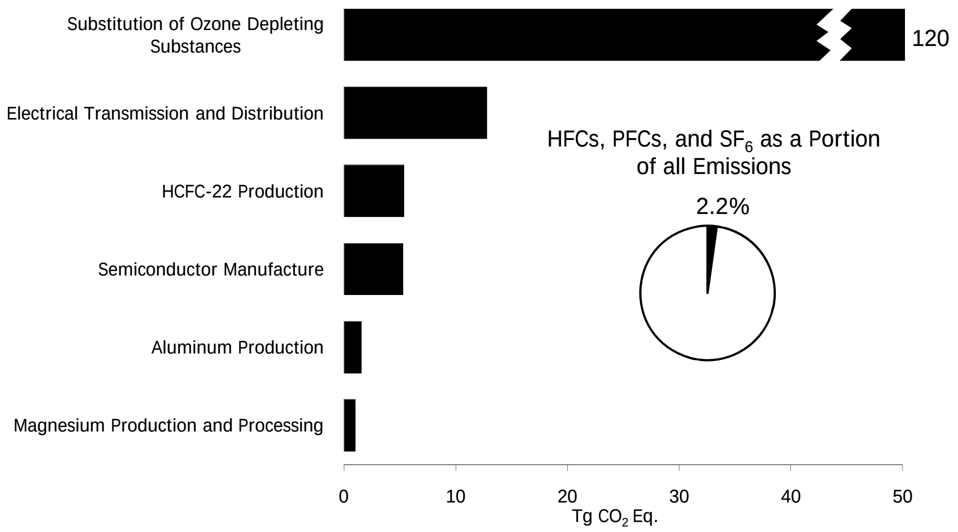
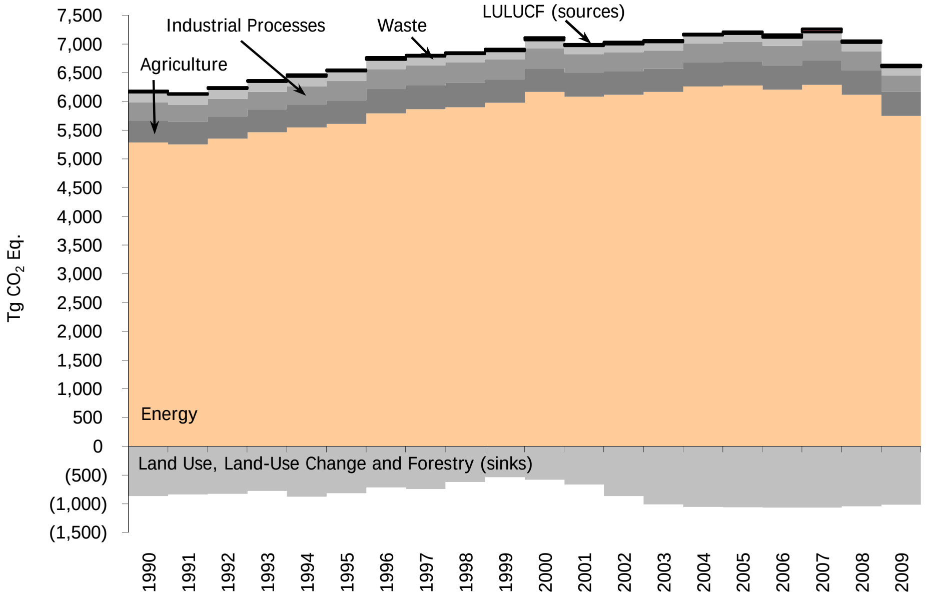


Figure ES-10: 2009 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

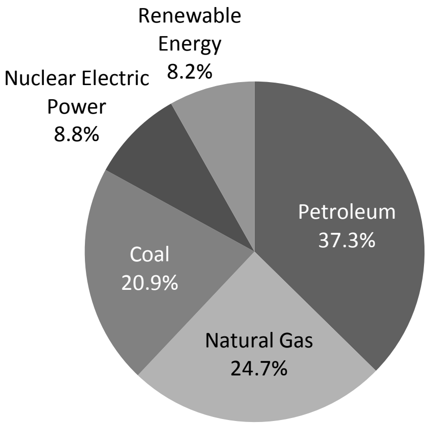


Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

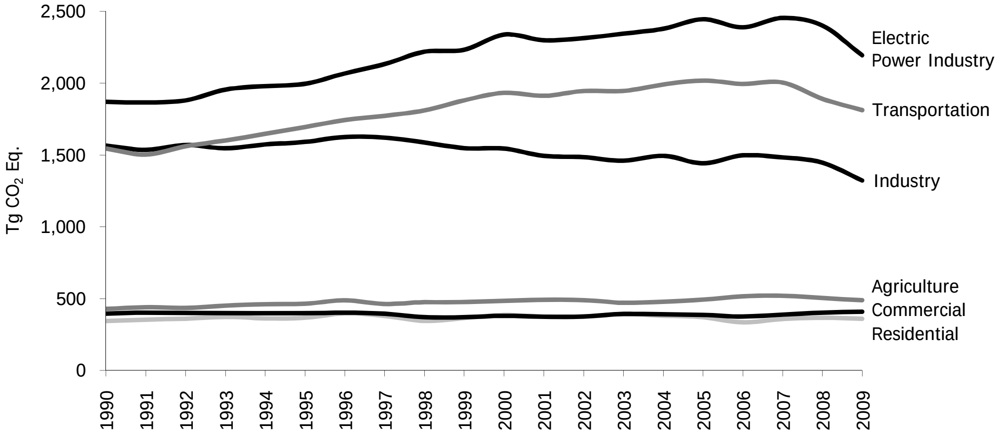


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

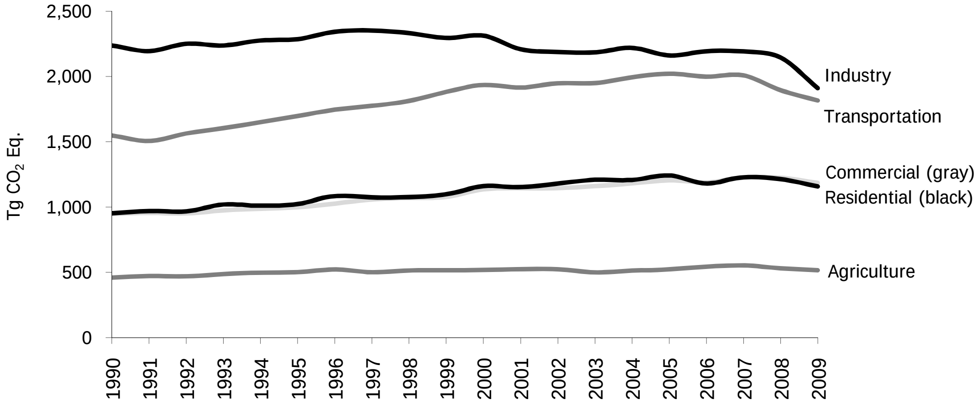


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

Note: Does not include U.S. Territories.

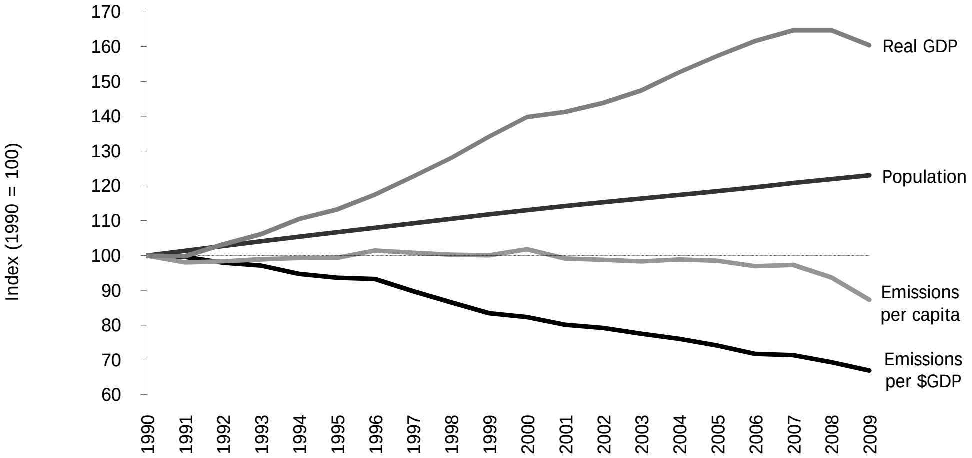


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

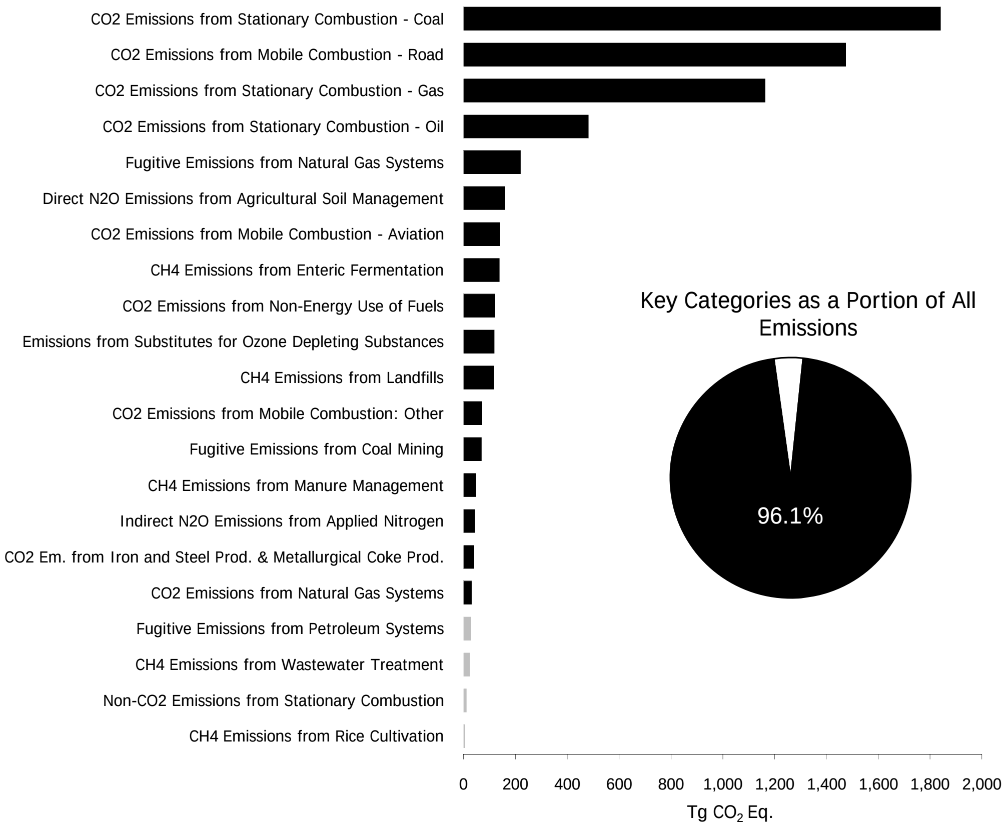


Figure ES-16: 2009 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

1. Introduction

This report presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and sinks for the years 1990 through 2009. A summary of these estimates is provided in Table 2.1 and Table 2.2 by gas and source category in the Trends in Greenhouse Gas Emissions chapter. The emission estimates in these tables are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis in order to show the relative contribution of each gas to global average radiative forcing.[20] This report also discusses the methods and data used to calculate these emission estimates.

In 1992, the United States signed and ratified the United Nations Framework Convention on Climate Change (UNFCCC). As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[21,22]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[23] The United States views this report as an opportunity to fulfill these commitments under the UNFCCC.

In 1988, preceding the creation of the UNFCCC, the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) jointly established the Intergovernmental Panel on Climate Change (IPCC). The role of the IPCC is to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation (IPCC 2003). Under Working Group 1 of the IPCC, nearly 140 scientists and national experts from more than thirty countries collaborated in the creation of the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997) to ensure that the emission inventories submitted to the UNFCCC are consistent and comparable between nations. The IPCC accepted the Revised 1996 IPCC Guidelines at its Twelfth Session (Mexico City, September 11-13, 1996). This report presents information in accordance with these guidelines. In addition, this Inventory is in accordance with the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories and the Good Practice Guidance for Land Use, Land-Use Change, and Forestry, which further expanded upon the methodologies in the Revised 1996 IPCC Guidelines. The IPCC has also accepted the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC 2006) at its Twenty-Fifth Session (Mauritius, April 2006). The 2006 IPCC Guidelines build on the previous bodies of work and includes new sources and gases "…as well as updates to the previously published methods whenever scientific and technical knowledge have improved since the previous guidelines were issued." Many of the methodological improvements presented in the 2006 Guidelines have been adopted in this Inventory.

Overall, this inventory of anthropogenic greenhouse gas emissions provides a common and consistent mechanism through which Parties to the UNFCCC can estimate emissions and compare the relative contribution of individual sources, gases, and nations to climate change. The inventory provides a national estimate of sources and sinks for the United States, including all states and U.S. territories[24] . The structure of this report is consistent with the current

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[20] See the section below entitled *Global Warming Potentials* for an explanation of GWP values.

[21] The term "anthropogenic", in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[22] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>. (UNEP/WMO 2000)

[23] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[24] U.S. Territories include American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands.

UNFCCC Guidelines on Annual Inventories (UNFCCC 2006).

[BEGIN BOX]

Box 1-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[25] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[26] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

1.1. Background Information

Science

For over the past 200 years, the burning of fossil fuels such as coal and oil, deforestation, and other sources have caused the concentrations of heat-trapping "greenhouse gases" to increase significantly in our atmosphere. These gases absorb some of the energy being radiated from the surface of the earth and trap it in the atmosphere, essentially acting like a blanket that makes the earth's surface warmer than it would be otherwise.

Greenhouse gases are necessary to life as we know it, because without them the planet's surface would be about 60 ºF cooler than present. But, as the concentrations of these gases continue to increase in the atmosphere, the Earth's temperature is climbing above past levels. According to NOAA and NASA data, the Earth's average surface temperature has increased by about 1.2 to 1.4 ºF since 1900. The ten warmest years on record (since 1850) have all occurred in the past 13 years (EPA 2009). Most of the warming in recent decades is very likely the result of human activities. Other aspects of the climate are also changing such as rainfall patterns, snow and ice cover, and sea level.

If greenhouse gases continue to increase, climate models predict that the average temperature at the Earth's surface could increase from 2.0 to 11.5 ºF above 1990 levels by the end of this century (IPCC 2007). Scientists are certain that human activities are changing the composition of the atmosphere, and that increasing the concentration of greenhouse gases will change the planet's climate. But they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.[27]

Greenhouse Gases

Although the Earth's atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide (CO_2), and other trace gases in the

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[25] See <http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[26] See <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>

[27] For more information see <http://www.epa.gov/climatechange/science>

atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 2001). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans.[28] A gauge of these changes is called radiative forcing, which is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system (IPCC 2001). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

> *Climate change can be driven by changes in the atmospheric concentrations of a number of radiatively active gases and aerosols. We have clear evidence that human activities have affected concentrations, distributions and life cycles of these gases (IPCC 1996).*

Naturally occurring greenhouse gases include water vapor, CO_2, methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in national greenhouse gas inventories.[29] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

There are also several gases that, although they do not have a commonly agreed upon direct radiative forcing effect, do influence the global radiation budget. These tropospheric gases include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and tropospheric (ground level) ozone O_3. Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight). Aerosols are extremely small particles or liquid droplets that are often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants. They can affect the absorptive characteristics of the atmosphere. Comparatively, however, the level of scientific understanding of aerosols is still very low (IPCC 2001).

CO_2, CH_4, and N_2O are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes, except when directly or indirectly perturbed out of equilibrium by anthropogenic activities, generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table 1-1.

Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime (years) of Selected Greenhouse Gases

Atmospheric Variable	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CF_4**
Pre-industrial atmospheric concentration	278 ppm	0.715 ppm	0.270 ppm	0 ppt	40 ppt
Atmospheric concentration	385 ppm	1.741-1.865 ppm[a]	0.321-0.322 ppm[a]	5.6 ppt	74 ppt
Rate of concentration change	1.4 ppm/yr	0.005 ppm/yr[b]	0.26%/yr	Linear[c]	Linear[c]
Atmospheric lifetime (years)	50-200[d]	12[e]	114[e]	3,200	>50,000

Source: Pre-industrial atmospheric concentrations and rate of concentration changes for all gases are from IPCC (2007). The current atmospheric concentration for CO_2 is from NOAA/ESRL (2009).

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[28] For more on the science of climate change, see NRC (2001).

[29] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in this document for informational purposes.

[a] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).
[b] The growth rate for atmospheric CH_4 has been decreasing from 1.4 ppb/yr in 1984 to less than 0 ppb/yr in 2001, 2004, and 2005.
[c] IPCC (2007) identifies the rate of concentration change for SF_6 and CF_4 as linear.
[d] No single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes.
[e] This lifetime has been defined as an "adjustment time" that takes into account the indirect effect of the gas on its own residence time.

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of GWPs, which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H_2O). Overall, the most abundant and dominant greenhouse gas in the atmosphere is water vapor. Water vapor is neither long-lived nor well mixed in the atmosphere, varying spatially from 0 to 2 percent (IPCC 1996). In addition, atmospheric water can exist in several physical states including gaseous, liquid, and solid. Human activities are not believed to affect directly the average global concentration of water vapor, but, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. While a warmer atmosphere has an increased water holding capacity, increased concentrations of water vapor affects the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Aircraft contrails, which consist of water vapor and other aircraft emittants, are similar to clouds in their radiative forcing effects (IPCC 1999).

Carbon Dioxide. In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO_2. Atmospheric CO_2 is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. CO_2 concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 385 ppmv in 2008, a 37.5 percent increase (IPCC 2007 and NOAA/ESRL 2009) .[30,31] The IPCC definitively states that "the present atmospheric CO_2 increase is caused by anthropogenic emissions of CO_2" (IPCC 2001). The predominant source of anthropogenic CO_2 emissions is the combustion of fossil fuels. Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of CO_2. In it's fourth assessment, the IPCC stated "most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increased in anthropogenic greenhouse gas concentrations," of which CO_2 is the most important (IPCC 2007)

Methane. CH_4 is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal solid wastes. CH_4 is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of CH_4 have increased by about 143 percent since 1750, from a pre-industrial value of about 722 ppb to 1,741-1,865 ppb in 2007[32], although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH_4 flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use, and waste disposal (IPCC 2007).

CH_4 is removed from the atmosphere through a reaction with the hydroxyl radical (OH) and is ultimately converted to CO_2. Minor removal processes also include reaction with chlorine in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of CH_4 reduce the concentration of OH, a feedback that may increase the atmospheric lifetime of CH_4 (IPCC 2001).

Nitrous Oxide. Anthropogenic sources of N_2O emissions include agricultural soils, especially production of

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[30] The pre-industrial period is considered as the time preceding the year 1750 (IPCC 2001).

[31] Carbon dioxide concentrations during the last 1,000 years of the pre-industrial period (i.e., 750-1750), a time of relative climate stability, fluctuated by about ±10 ppmv around 280 ppmv (IPCC 2001).

[32] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009)

nitrogen-fixing crops and forages, the use of synthetic and manure fertilizers, and manure deposition by livestock; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste incineration; and biomass burning. The atmospheric concentration of N_2O has increased by 18 percent since 1750, from a pre-industrial value of about 270 ppb to 321-322 ppb in 2007[33], a concentration that has not been exceeded during the last thousand years. N_2O is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere (IPCC 2007).

Ozone. Ozone is present in both the upper stratosphere,[34] where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,[35] where it is the main component of anthropogenic photochemical "smog." During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as CFCs, have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 1996). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover. As of IPCC's fourth assessment,"whether or not recently observed changes in ozone trends are already indicative of recovery of the global ozone layer is not yet clear." (IPCC 2007)

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the third largest increase in direct radiative forcing since the pre-industrial era, behind CO_2 and CH_4. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds mixing with NO_x in the presence of sunlight. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable. (IPCC 2001)

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride. Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine (CFCs, HCFCs, methyl chloroform, and carbon tetrachloride) and bromine (halons, methyl bromide, and hydrobromofluorocarbons [HFCs]) result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which itself is an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5[36] countries beginning in 1996, and then followed by a complete phase-out by the year 2030. While ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC; they are reported in this inventory under Annex 6.2 of this report for informational purposes.

HFCs, PFCs, and SF_6 are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs are primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process. Currently, they have a small aggregate radiative forcing impact, but it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2001). PFCs and SF_6 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium

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[33] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).

[34] The stratosphere is the layer from the troposphere up to roughly 50 kilometers. In the lower regions the temperature is nearly constant but in the upper layer the temperature increases rapidly because of sunlight absorption by the ozone layer. The ozone-layer is the part of the stratosphere from 19 kilometers up to 48 kilometers where the concentration of ozone reaches up to 10 parts per million.

[35] The troposphere is the layer from the ground up to 11 kilometers near the poles and up to 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere where people live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for most weather processes, including most of the water vapor and clouds.

[36] Article 5 of the Montreal Protocol covers several groups of countries, especially developing countries, with low consumption rates of ozone depleting substances. Developing countries with per capita consumption of less than 0.3 kg of certain ozone depleting substances (weighted by their ozone depleting potential) receive financial assistance and a grace period of ten additional years in the phase-out of ozone depleting substances.

casting. Currently, the radiative forcing impact of PFCs and SF_6 is also small, but they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2001).

Carbon Monoxide. Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH_4 and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO_2. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides. The primary climate change effects of nitrogen oxides (i.e., NO and NO_2) are indirect and result from their role in promoting the formation of ozone in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects.[37] Additionally, NO_x emissions from aircraft are also likely to decrease CH_4 concentrations, thus having a negative radiative forcing effect (IPCC 1999). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning (both natural and anthropogenic fires) fuel combustion, and, in the stratosphere, from the photo-degradation of N_2O. Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Non-CH_4 volatile organic compounds include substances such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere. They can be produced by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. Aerosols affect radiative forcing differently than greenhouse gases, and their radiative effects occur through direct and indirect mechanisms: directly by scattering and absorbing solar radiation; and indirectly by increasing droplet counts that modify the formation, precipitation efficiency, and radiative properties of clouds. Aerosols are removed from the atmosphere relatively rapidly by precipitation. Because aerosols generally have short atmospheric lifetimes, and have concentrations and compositions that vary regionally, spatially, and temporally, their contributions to radiative forcing are difficult to quantify (IPCC 2001).

The indirect radiative forcing from aerosols is typically divided into two effects. The first effect involves decreased droplet size and increased droplet concentration resulting from an increase in airborne aerosols. The second effect involves an increase in the water content and lifetime of clouds due to the effect of reduced droplet size on precipitation efficiency (IPCC 2001). Recent research has placed a greater focus on the second indirect radiative forcing effect of aerosols.

Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulfates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous[38] aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols on radiative forcing is believed to be negative (i.e., net cooling effect on the climate), although because they remain in the atmosphere for only days to weeks, their concentrations respond rapidly to changes in emissions.[39] Locally, the negative radiative forcing effects of aerosols can offset the positive forcing of greenhouse gases (IPCC 1996). "However, the aerosol effects do not cancel the global-scale effects of the much longer-lived greenhouse gases, and significant climate changes can still result" (IPCC 1996).

The IPCC's Third Assessment Report notes that "the indirect radiative effect of aerosols is now understood to also

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[37] NO_x emissions injected higher in the stratosphere, primarily from fuel combustion emissions from high altitude supersonic aircraft, can lead to stratospheric ozone depletion.

[38] Carbonaceous aerosols are aerosols that are comprised mainly of organic substances and forms of black carbon (or soot) (IPCC 2001).

[39] Volcanic activity can inject significant quantities of aerosol producing sulfur dioxide and other sulfur compounds into the stratosphere, which can result in a longer negative forcing effect (i.e., a few years) (IPCC 1996).

encompass effects on ice and mixed-phase clouds, but the magnitude of any such indirect effect is not known, although it is likely to be positive" (IPCC 2001). Additionally, current research suggests that another constituent of aerosols, black carbon, has a positive radiative forcing, and that its presence "in the atmosphere above highly reflective surfaces such as snow and ice, or clouds, may cause a significant positive radiative forcing (IPCC 2007). The primary anthropogenic emission sources of black carbon include diesel exhaust and open biomass burning.

Global Warming Potentials

A global warming potential is a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas (see Table 1-2). It is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The reference gas used is CO_2, and therefore GWP weighted emissions are measured in teragrams of CO_2 equivalent (Tg CO_2 Eq.)[40] The relationship between gigagrams (Gg) of a gas and Tg CO_2 Eq. can be expressed as follows:

$$\text{Tg CO}_2\text{ Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1{,}000\,\text{Gg}}\right)$$

where,

Tg CO_2 Eq. = Teragrams of CO_2 Equivalents

Gg = Gigagrams (equivalent to a thousand metric tons)

GWP = Global Warming Potential

Tg = Teragrams

GWP values allow for a comparison of the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of ±35 percent. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available.

> *Greenhouse gas emissions and removals should be presented on a gas-by-gas basis in units of mass... In addition, consistent with decision 2/CP.3, Parties should report aggregate emissions and removals of greenhouse gases, expressed in CO_2 equivalent terms at summary inventory level, using GWP values provided by the IPCC in its Second Assessment Report... based on the effects of greenhouse gases over a 100-year time horizon.*[41]

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, ozone precursors (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and carbonaceous particles), however, vary regionally, and consequently it is difficult to quantify their global radiative forcing impacts. No GWP values are attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report

Gas	Atmospheric Lifetime	GWP[a]
CO_2	50-200	1

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[40] Carbon comprises 12/44$^{\text{ths}}$ of carbon dioxide by weight.

[41] Framework Convention on Climate Change; <http://unfccc.int/resource/docs/cop8/08.pdf>; 1 November 2002; Report of the Conference of the Parties at its eighth session; held at New Delhi from 23 October to 1 November 2002; Addendum; Part One: Action taken by the Conference of the Parties at its eighth session; Decision -/CP.8; Communications from Parties included in Annex I to the Convention: Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention, Part 1: UNFCCC reporting guidelines on annual inventories; p. 7. (UNFCCC 2003)

CH4[b]	12±3	21
N_2O	120	310
HFC-23	264	11,700
HFC-32	5.6	650
HFC-125	32.6	2,800
HFC-134a	14.6	1,300
HFC-143a	48.3	3,800
HFC-152a	1.5	140
HFC-227ea	36.5	2,900
HFC-236fa	209	6,300
HFC-4310mee	17.1	1,300
CF_4	50,000	6,500
C_2F_6	10,000	9,200
C_4F_{10}	2,600	7,000
C_6F_{14}	3,200	7,400
SF_6	3,200	23,900

Source: (IPCC 1996)

[a] 100-year time horizon

[b] The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

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Box 1-2: The IPCC Fourth Assessment Report and Global Warming Potentials

In 2007, the IPCC published its Fourth Assessment Report (AR4), which provided an updated and more comprehensive scientific assessment of climate change. Within this report, the GWPs of several gases were revised relative to the SAR and the IPCC's Third Assessment Report (TAR) (IPCC 2001). Thus the GWPs used in this report have been updated twice by the IPCC; although the SAR GWPs are used throughout this report, it is interesting to review the changes to the GWPs and the impact such improved understanding has on the total GWP-weighted emissions of the United States. Since the SAR and TAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function. The GWPs are drawn from IPCC/TEAP (2005) and the TAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. In addition, the values for radiative forcing and lifetimes have been recalculated for a variety of halocarbons, which were not presented in the SAR. Table 1-3 presents the new GWPs, relative to those presented in the SAR.

Table 1-3: Comparison of 100-Year GWPs

Gas	**SAR**	**TAR**	**AR4**	**Change from SAR**	
				TAR	**AR4**
CO_2	1	1	1	NC	0
CH_4*	21	23	25	2	4
N_2O	310	296	298	(14)	(12)
HFC-23	11,700	12,000	14,800	300	3,100
HFC-32	650	550	675	(100)	25
HFC-125	2,800	3,400	3,500	600	700
HFC-134a	1,300	1,300	1,430	NC	130
HFC-143a	3,800	4,300	4,470	500	670
HFC-152a	140	120	124	(20)	(16)
HFC-227ea	2,900	3,500	3,220	600	320
HFC-236fa	6,300	9,400	9,810	3,100	3,510
HFC-4310mee	1,300	1,500	1,640	200	340
CF_4	6,500	5,700	7,390	(800)	890
C_2F_6	9,200	11,900	12,200	2,700	3,000

C_4F_10	7,000	8,600	8,860	1,600	1,860
C6F14	7,400	9,000	9,300	1,600	1,900
SF_6	23,900	22,200	22,800	(1,700)	(1,100)

Source: (IPCC 2007, IPCC 2001)
NC (No Change)
Note: Parentheses indicate negative values.
* The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. The UNFCCC reporting guidelines for national inventories[42] were updated in 2002 but continue to require the use of GWPs from the SAR so that current estimates of aggregate greenhouse gas emissions for 1990 through 2009 are consistent and comparable with estimates developed prior to the publication of the TAR and AR4. For informational purposes, emission estimates that use the updated GWPs are presented in detail in Annex 6.1 of this report. All estimates provided throughout this report are also presented in unweighted units.

[END BOX]

1.2. Institutional Arrangements

The U.S. Environmental Protection Agency (EPA), in cooperation with other U.S. government agencies, prepares the Inventory of U.S. Greenhouse Gas Emissions and Sinks. A wide range of agencies and individuals are involved in supplying data to, reviewing, or preparing portions of the U.S. Inventory—including federal and state government authorities, research and academic institutions, industry associations, and private consultants.

Within EPA, the Office of Atmospheric Programs (OAP) is the lead office responsible for the emission calculations provided in the Inventory, as well as the completion of the National Inventory Report and the Common Reporting Format tables. The Office of Transportation and Air Quality (OTAQ) is also involved in calculating emissions for the Inventory. While the U.S. Department of State officially submits the annual Inventory to the UNFCCC, EPA's OAP serves as the focal point for technical questions and comments on the U.S. Inventory. The staff of OAP and OTAQ coordinates the annual methodological choice, activity data collection, and emission calculations at the individual source category level. Within OAP, an inventory coordinator compiles the entire Inventory into the proper reporting format for submission to the UNFCCC, and is responsible for the collection and consistency of cross-cutting issues in the Inventory.

Several other government agencies contribute to the collection and analysis of the underlying activity data used in the Inventory calculations. Formal relationships exist between EPA and other U.S. agencies that provide official data for use in the Inventory. The U.S. Department of Energy's Energy Information Administration provides national fuel consumption data and the U.S. Department of Defense provides military fuel consumption and bunker fuels. Informal relationships also exist with other U.S. agencies to provide activity data for use in EPA's emission calculations. These include: the U.S. Department of Agriculture, the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, and the Federal Aviation Administration. Academic and research centers also provide activity data and calculations to EPA, as well as individual companies participating in voluntary outreach efforts with EPA. Finally, the U.S. Department of State officially submits the Inventory to the UNFCCC each April.

1.3. Inventory Process

EPA has a decentralized approach to preparing the annual U.S. Inventory, which consists of a National Inventory Report (NIR) and Common Reporting Format (CRF) tables. The Inventory coordinator at EPA is responsible for

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[42] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

compiling all emission estimates, and ensuring consistency and quality throughout the NIR and CRF tables. Emission calculations for individual sources are the responsibility of individual source leads, who are most familiar with each source category and the unique characteristics of its emissions profile. The individual source leads determine the most appropriate methodology and collect the best activity data to use in the emission calculations, based upon their expertise in the source category, as well as coordinating with researchers and contractors familiar with the sources. A multi-stage process for collecting information from the individual source leads and producing the Inventory is undertaken annually to compile all information and data.

Methodology Development, Data Collection, and Emissions and Sink Estimation

Source leads at EPA collect input data and, as necessary, evaluate or develop the estimation methodology for the individual source categories. For most source categories, the methodology for the previous year is applied to the new "current" year of the Inventory, and inventory analysts collect any new data or update data that have changed from the previous year. If estimates for a new source category are being developed for the first time, or if the methodology is changing for an existing source category (e.g., the United States is implementing a higher Tiered approach for that source category), then the source category lead will develop a new methodology, gather the most appropriate activity data and emission factors (or in some cases direct emission measurements) for the entire time series, and conduct a special source-specific peer review process involving relevant experts from industry, government, and universities.

Once the methodology is in place and the data are collected, the individual source leads calculate emissions and sink estimates. The source leads then update or create the relevant text and accompanying annexes for the Inventory. Source leads are also responsible for completing the relevant sectoral background tables of the Common Reporting Format, conducting quality assurance and quality control (QA/QC) checks, and uncertainty analyses.

Summary Spreadsheet Compilation and Data Storage

The inventory coordinator at EPA collects the source categories' descriptive text and Annexes, and also aggregates the emission estimates into a summary spreadsheet that links the individual source category spreadsheets together. This summary sheet contains all of the essential data in one central location, in formats commonly used in the Inventory document. In addition to the data from each source category, national trend and related data are also gathered in the summary sheet for use in the Executive Summary, Introduction, and Recent Trends sections of the Inventory report. Electronic copies of each year's summary spreadsheet, which contains all the emission and sink estimates for the United States, are kept on a central server at EPA under the jurisdiction of the Inventory coordinator.

National Inventory Report Preparation

The NIR is compiled from the sections developed by each individual source lead. In addition, the inventory coordinator prepares a brief overview of each chapter that summarizes the emissions from all sources discussed in the chapters. The inventory coordinator then carries out a key category analysis for the Inventory, consistent with the IPCC Good Practice Guidance, IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry, and in accordance with the reporting requirements of the UNFCCC. Also at this time, the Introduction, Executive Summary, and Recent Trends sections are drafted, to reflect the trends for the most recent year of the current Inventory. The analysis of trends necessitates gathering supplemental data, including weather and temperature conditions, economic activity and gross domestic product, population, atmospheric conditions, and the annual consumption of electricity, energy, and fossil fuels. Changes in these data are used to explain the trends observed in greenhouse gas emissions in the United States. Furthermore, specific factors that affect individual sectors are researched and discussed. Many of the factors that affect emissions are included in the Inventory document as separate analyses or side discussions in boxes within the text. Text boxes are also created to examine the data aggregated in different ways than in the remainder of the document, such as a focus on transportation activities or emissions from electricity generation. The document is prepared to match the specification of the UNFCCC reporting guidelines for National Inventory Reports.

Common Reporting Format Table Compilation

The CRF tables are compiled from individual tables completed by each individual source lead, which contain source emissions and activity data. The inventory coordinator integrates the source data into the UNFCCC's "CRF Reporter" for the United States, assuring consistency across all sectoral tables. The summary reports for emissions, methods, and emission factors used, the overview tables for completeness and quality of estimates, the recalculation tables, the notation key completion tables, and the emission trends tables are then completed by the inventory coordinator. Internal automated quality checks on the CRF Reporter, as well as reviews by the source leads, are completed for the entire time series of CRF tables before submission.

QA/QC and Uncertainty

QA/QC and uncertainty analyses are supervised by the QA/QC and Uncertainty coordinators, who have general oversight over the implementation of the QA/QC plan and the overall uncertainty analysis for the Inventory (see sections on QA/QC and Uncertainty, below). These coordinators work closely with the source leads to ensure that a consistent QA/QC plan and uncertainty analysis is implemented across all inventory sources. The inventory QA/QC plan, detailed in a following section, is consistent with the quality assurance procedures outlined by EPA and IPCC.

Expert and Public Review Periods

During the Expert Review period, a first draft of the document is sent to a select list of technical experts outside of EPA. The purpose of the Expert Review is to encourage feedback on the methodological and data sources used in the current Inventory, especially for sources which have experienced any changes since the previous Inventory.

Once comments are received and addressed, a second draft of the document is released for public review by publishing a notice in the U.S. Federal Register and posting the document on the EPA Web site. The Public Review period allows for a 30 day comment period and is open to the entire U.S. public.

Final Submittal to UNFCCC and Document Printing

After the final revisions to incorporate any comments from the Expert Review and Public Review periods, EPA prepares the final National Inventory Report and the accompanying Common Reporting Format Reporter database. The U.S. Department of State sends the official submission of the U.S. Inventory to the UNFCCC. The document is then formatted for printing, posted online, printed by the U.S. Government Printing Office, and made available for the public.

1.4. Methodology and Data Sources

Emissions of greenhouse gases from various source and sink categories have been estimated using methodologies that are consistent with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997). In addition, the United States references the additional guidance provided in the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003), and the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). To the extent possible, the present report relies on published activity and emission factor data. Depending on the emission source category, activity data can include fuel consumption or deliveries, vehicle-miles traveled, raw material processed, etc. Emission factors are factors that relate quantities of emissions to an activity.

The IPCC methodologies provided in the Revised 1996 IPCC Guidelines represent baseline methodologies for a variety of source categories, and many of these methodologies continue to be improved and refined as new research and data become available. This report uses the IPCC methodologies when applicable, and supplements them with other available methodologies and data where possible. Choices made regarding the methodologies and data sources used are provided in conjunction with the discussion of each source category in the main body of the report. Complete documentation is provided in the annexes on the detailed methodologies and data sources utilized in the calculation of each source category.

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Box 1-3: IPCC Reference Approach

The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating CO_2 emissions from fossil fuel combustion in addition to their “bottom-up” sectoral methodology. This estimation method uses alternative methodologies and different data sources than those contained in that section of the Energy chapter. The reference approach estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys (see Annex 4 of this report). The reference approach assumes that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required.

[END BOX]

1.5. Key Categories

The IPCC’s Good Practice Guidance (IPCC 2000) defines a key category as a “[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country’s total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both.”[43] By definition, key categories include those sources that have the greatest contribution to the absolute level of national emissions. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends and uncertainties of individual source and sink categories. This analysis culls out source and sink categories that diverge from the overall trend in national emissions. Finally, a qualitative evaluation of key categories is performed to capture any categories that were not identified in any of the quantitative analyses.

A Tier 1 approach, as defined in the IPCC’s Good Practice Guidance (IPCC 2000), was implemented to identify the key categories for the United States. This analysis was performed twice; one analysis included sources and sinks from the Land Use, Land-Use Change, and Forestry (LULUCF) sector, the other analysis did not include the LULUCF categories. Following the Tier 1 approach, a Tier 2 approach, as defined in the IPCC’s Good Practice Guidance (IPCC 2000), was then implemented to identify any additional key categories not already identified in the Tier 1 assessment. This analysis, which includes each source categories’ uncertainty assessments (or proxies) in its calculations, was also performed twice to include or exclude LULUCF categories.

In addition to conducting Tier 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC’s Good Practice Guidance (IPCC 2000), was conducted to capture any key categories that were not identified by either quantitative method. One additional key category, international bunker fuels, was identified using this qualitative assessment. International bunker fuels are fuels consumed for aviation or marine international transport activities, and emissions from these fuels are reported separately from totals in accordance with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to the Tier 1 approach. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, because it would qualify bunker fuels as a key category according to the Tier 2 approach. Table 1-4 presents the key categories for the United States (including and excluding LULUCF categories) using emissions and uncertainty data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2009. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Tier 1, Tier 2, and/or qualitative assessments). Annex 1 of this report provides additional information regarding the key categories in the United States and the methodologies used to identify them.

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[43] See Chapter 7 “Methodological Choice and Recalculation” in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

Table 1-4: Key Categories for the United States (1990-2009)

IPCC Source Categories	Gas	Tier 1 Level Without LULUCF	Tier 1 Trend Without LULUCF	Tier 1 Level With LULUCF	Tier 1 Trend With LULUCF	Tier 2 Level Without LULUCF	Tier 2 Trend Without LULUCF	Tier 2 Level With LULUCF	Tier 2 Trend With LULUCF	Qual[a]	2009 Emissions (Tg CO_2 Eq.)
Energy											
CO_2 Emissions from Stationary Combustion - Coal	CO_2	•		•	•	•		•	•		1,841.0
CO_2 Emissions from Mobile Combustion: Road	CO_2	•	•	•	•	•	•	•	•		1,475.6
CO_2 Emissions from Stationary Combustion - Gas	CO_2	•	•	•	•	•	•	•	•		1,164.6
CO_2 Emissions from Stationary Combustion - Oil	CO_2	•	•	•	•	•	•	•	•		483.3
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	•	•	•	•	•	•	•	•		140.7
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	•		•	•	•		•			123.4
CO_2 Emissions from Mobile Combustion: Other	CO_2	•	•	•	•						73.5
CO_2 Emissions from Natural Gas Systems	CO_2	•	•	•	•	•	•	•	•		32.2
CO_2 Emissions from Mobile Combustion: Marine	CO_2	•	•	•	•						30.0
Fugitive Emissions from Natural Gas Systems	CH_4	•	•	•	•	•	•	•	•		221.2
Fugitive Emissions from Coal Mining	CH_4	•	•	•	•	•	•	•	•		71.0
Fugitive Emissions from Petroleum Systems	CH_4	•	•	•	•	•	•	•	•		30.9
Non-CO_2 Emissions from Stationary Combustion	CH_4						•		•		6.2
N_2O Emissions from Mobile Combustion: Road	N_2O	•	•	•	•		•		•		20.3
Non-CO_2 Emissions from Stationary Combustion	N_2O					•		•			12.8
International Bunker Fuels[b]	Several									•	124.4
Industrial Processes											
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	•	•	•	•	•	•	•	•		41.9
CO_2 Emissions from Cement Production	CO_2		•	•	•						29.0
CO_2 Emissions from Ammonia Production and Urea Consumption	CO_2		•		•						11.8
CO_2 Emissions from Aluminum Production	CO_2										3.0
N_2O Emissions from Nitric Acid Production	N_2O				•		•				14.6
N_2O Emissions from Adipic Acid Production	N_2O		•		•		•		•		1.9
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•		•	•	•		120.0
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP		•		•		•		•		12.8
HFC-23 Emissions from HCFC-22 Production	HiGWP	•	•	•	•		•		•		5.4

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual[a]	2009 Emissions (Tg CO_2 Eq.)
		Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF		
PFC Emissions from Aluminum Production	HiGWP		●		●		●				1.6
SF_6 Emissions from Magnesium Production and Processing	HiGWP		●		●						1.1
Agriculture											
CH_4 Emissions from Enteric Fermentation	CH_4	●		●		●		●			139.8
CH_4 Emissions from Manure Management	CH_4	●	●	●	●		●		●		49.5
CH_4 Emissions from Rice Cultivation	CH_4					●		●			7.3
Direct N_2O Emissions from Agricultural Soil Management	N_2O	●	●	●	●	●	●	●	●		160.2
Indirect N_2O Emissions from Applied Nitrogen	N_2O	●		●		●	●	●	●		44.4
Waste											
CH_4 Emissions from Landfills	CH_4	●	●	●	●	●	●	●	●		117.5
CH_4 Emissions from Wastewater Treatment	CH_4					●		●			24.5
Land Use, Land Use Change, and Forestry											
CO_2 Emissions from Changes in Forest Carbon Stocks	CO_2			●	●			●	●		(863.1)
CO_2 Emissions from Urban Trees	CO_2			●	●			●	●		(95.9)
CO_2 Emissions from Cropland Remaining Cropland	CO_2				●			●	●		(17.4)
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2				●			●	●		(12.6)
CO_2 Emissions from Grassland Remaining Grassland	CO_2			●	●			●	●		(8.3)
CH_4 Emissions from Forest Fires	CH_4							●	●		7.8
N_2O Emissions from Forest Fires	N_2O								●		6.4
Subtotal Without LULUCF											**6,512.7**
Total Emissions Without LULUCF											**6,608.2**
Percent of Total Without LULUCF											**99%**
Subtotal With LULUCF											**5,529.5**
Total Emissions With LULUCF											**5,618.2**
Percent of Total With LULUCF											**98%**

[a] Qualitative criteria.

[b] Emissions from this source not included in totals.

Note: Parentheses indicate negative values (or sequestration).

1.6. Quality Assurance and Quality Control (QA/QC)

As part of efforts to achieve its stated goals for inventory quality, transparency, and credibility, the United States has developed a quality assurance and quality control plan designed to check, document and improve the quality of its inventory over time. QA/QC activities on the Inventory are undertaken within the framework of the U.S. QA/QC plan, Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory: Procedures Manual for QA/QC and Uncertainty Analysis.

Key attributes of the QA/QC plan are summarized in Figure 1-1. These attributes include:

- specific detailed procedures and forms that serve to standardize the process of documenting and archiving information, as well as to guide the implementation of QA/QC and the analysis of the uncertainty of the inventory estimates;
- expert review as well as QC—for both the inventory estimates and the Inventory (which is the primary vehicle for disseminating the results of the inventory development process). In addition, the plan provides for public review of the Inventory;
- both Tier 1 (general) and Tier 2 (source-specific) quality controls and checks, as recommended by IPCC Good Practice Guidance;
- consideration of secondary data quality and source-specific quality checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates provides for more structured communication and integration with the suppliers of secondary information;
- record-keeping provisions to track which procedures have been followed, and the results of the QA/QC and uncertainty analysis, and contains feedback mechanisms for corrective action based on the results of the investigations, thereby providing for continual data quality improvement and guided research efforts;
- implementation of QA/QC procedures throughout the whole inventory development process—from initial data collection, through preparation of the emission estimates, to publication of the Inventory;
- a schedule for multi-year implementation; and
- promotion of coordination and interaction within the EPA, across Federal agencies and departments, state government programs, and research institutions and consulting firms involved in supplying data or preparing estimates for the inventory. The QA/QC plan itself is intended to be revised and reflect new information that becomes available as the program develops, methods are improved, or additional supporting documents become necessary.

In addition, based on the national QA/QC plan for the Inventory, source-specific QA/QC plans have been developed for a number of sources. These plans follow the procedures outlined in the national QA/QC plan, tailoring the procedures to the specific text and spreadsheets of the individual sources. For each greenhouse gas emissions source or sink included in this Inventory, a minimum of a Tier 1 QA/QC analysis has been undertaken. Where QA/QC activities for a particular source go beyond the minimum Tier 1 level, further explanation is provided within the respective source category text.

The quality control activities described in the U.S. QA/QC plan occur throughout the inventory process; QA/QC is not separate from, but is an integral part of, preparing the inventory. Quality control—in the form of both good practices (such as documentation procedures) and checks on whether good practices and procedures are being followed—is applied at every stage of inventory development and document preparation. In addition, quality assurance occurs at two stages—an expert review and a public review. While both phases can significantly contribute to inventory quality, the public review phase is also essential for promoting the openness of the inventory development process and the transparency of the inventory data and methods.

The QA/QC plan guides the process of ensuring inventory quality by describing data and methodology checks, developing processes governing peer review and public comments, and developing guidance on conducting an analysis of the uncertainty surrounding the emission estimates. The QA/QC procedures also include feedback loops and provide for corrective actions that are designed to improve the inventory estimates over time.

Figure 1-1: U.S. QA/QC Plan Summary

1.7. Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete and transparent emissions inventory. Uncertainty information is not intended to dispute the validity of the inventory estimates, but to help prioritize efforts to improve the accuracy of future inventories and guide future decisions on methodological choice. While the U.S. Inventory calculates its emission estimates with the highest possible accuracy, uncertainties are associated to a varying degree with the development of emission estimates for any inventory. Some of the current estimates, such as those for CO_2 emissions from energy-related activities, are considered to have minimal uncertainty associated with them. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty surrounding the estimates presented. Despite these uncertainties, the UNFCCC reporting guidelines follow the recommendation in the 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997) and require that countries provide single point estimates for each gas and emission or removal source category. Within the discussion of each emission source, specific factors affecting the uncertainty associated with the estimates are discussed.

Additional research in the following areas could help reduce uncertainty in the U.S. Inventory:

- *Incorporating excluded emission sources.* Quantitative estimates for some of the sources and sinks of greenhouse gas emissions are not available at this time. In particular, emissions from some land-use activities and industrial processes are not included in the inventory either because data are incomplete or because methodologies do not exist for estimating emissions from these source categories. See Annex 5 of this report for a discussion of the sources of greenhouse gas emissions and sinks excluded from this report.
- *Improving the accuracy of emission factors.* Further research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources. For example, the accuracy of current emission factors applied to CH_4 and N_2O emissions from stationary and mobile combustion is highly uncertain.
- *Collecting detailed activity data.* Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF_6 from electrical transmission and distribution is limited due to a lack of activity data regarding national SF_6 consumption or average equipment leak rates.

The overall uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the IPCC Tier 2 uncertainty estimation methodology. Estimates of quantitative uncertainty for the overall greenhouse gas emissions inventory are shown below, in Table 1-5.

The IPCC provides good practice guidance on two approaches—Tier 1 and Tier 2—to estimating uncertainty for individual source categories. Tier 2 uncertainty analysis, employing the Monte Carlo Stochastic Simulation technique, was applied wherever data and resources permitted; further explanation is provided within the respective source category text and in Annex 7. Consistent with the IPCC Good Practice Guidance (IPCC 2000), over a multi-year timeframe, the United States expects to continue to improve the uncertainty estimates presented in this report.

Table 1-5. Estimated Overall Inventory Quantitative Uncertainty (Tg CO_2 Eq. and Percent)

Gas	2009 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)		(%)		Mean[c] (Tg CO_2 Eq.)	Standard Deviation[c] (Tg CO_2 Eq.)
		Lower Bound[d]	Upper Bound[d]	Lower Bound	Upper Bound		
CO_2	5,504.8	5,436.6	5,813.8	-1%	6%	5,622.5	97.5
CH_4[e]	686.3	623.9	805.4	-9%	17%	702.8	45.3
N_2O[e]	295.6	261.7	425.3	-11%	44%	334.2	42.1
PFC, HFC & SF_6[e]	143.3	134.5	153.4	-6%	7%	143.7	4.8
Total	**6,630.0**	**6,584.2**	**7,033.6**	**-1%**	**6%**	**6,803.2**	**115.0**
Net Emissions (Sources and Sinks)	**5,614.9**	**5,512.3**	**6,055.1**	**-2%**	**8%**	**5,785.4**	**139.1**

Notes:

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed this year. Thus the totals reported in this table exclude approximately 3.1 Tg CO_2 Eq. of emissions for

which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory.

[b] The lower and upper bounds for emission estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.

[c] Mean value indicates the arithmetic average of the simulated emission estimates; standard deviation indicates the extent of deviation of the simulated values from the mean.

[d] The lower and upper bound emission estimates for the sub-source categories do not sum to total emissions because the low and high estimates for total emissions were calculated separately through simulations.

[e] The overall uncertainty estimates did not take into account the uncertainty in the GWP values for CH_4, N_2O and high GWP gases used in the inventory emission calculations for 2009.

Emissions calculated for the U.S. Inventory reflect current best estimates; in some cases, however, estimates are based on approximate methodologies, assumptions, and incomplete data. As new information becomes available in the future, the United States will continue to improve and revise its emission estimates. See Annex 7 of this report for further details on the U.S. process for estimating uncertainty associated with the emission estimates and for a more detailed discussion of the limitations of the current analysis and plans for improvement. Annex 7 also includes details on the uncertainty analysis performed for selected source categories.

1.8. Completeness

This report, along with its accompanying CRF reporter, serves as a thorough assessment of the anthropogenic sources and sinks of greenhouse gas emissions for the United States for the time series 1990 through 2009. Although this report is intended to be comprehensive, certain sources have been identified yet excluded from the estimates presented for various reasons. Generally speaking, sources not accounted for in this inventory are excluded due to data limitations or a lack of thorough understanding of the emission process. The United States is continually working to improve upon the understanding of such sources and seeking to find the data required to estimate related emissions. As such improvements are implemented, new emission sources are quantified and included in the Inventory. For a complete list of sources not included, see Annex 5 of this report.

1.9. Organization of Report

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2006 UNFCCC Guidelines on Reporting and Review (UNFCCC 2006), this Inventory of U.S. Greenhouse Gas Emissions and Sinks is segregated into six sector-specific chapters, listed below in Table 1-6. In addition, chapters on Trends in Greenhouse Gas Emissions and Other information to be considered as part of the U.S. Inventory submission are included.

Table 1-6: IPCC Sector Descriptions

Chapter/IPCC Sector	Activities Included
Energy	Emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions.
Industrial Processes	By-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion.
Solvent and Other Product Use	Emissions, of primarily NMVOCs, resulting from the use of solvents and N_2O from product uses.
Agriculture	Anthropogenic emissions from agricultural activities except fuel combustion, which is addressed under Energy.
Land Use, Land-Use Change, and Forestry	Emissions and removals of CO_2, CH_4, and N_2O from forest management, other land-use activities, and land-use change.
Waste	Emissions from waste management activities.

Source: (IPCC/UNEP/OECD/IEA 1997)

Within each chapter, emissions are identified by the anthropogenic activity that is the source or sink of the greenhouse gas emissions being estimated (e.g., coal mining). Overall, the following organizational structure is consistently applied throughout this report:

Chapter/IPCC Sector: Overview of emission trends for each IPCC defined sector

Source category: Description of source pathway and emission trends.

Methodology: Description of analytical methods employed to produce emission estimates and identification of data references, primarily for activity data and emission factors.

Uncertainty: A discussion and quantification of the uncertainty in emission estimates and a discussion of time-series consistency.

QA/QC and Verification: A discussion on steps taken to QA/QC and verify the emission estimates, where beyond the overall U.S. QA/QC plan, and any key findings.

Recalculations: A discussion of any data or methodological changes that necessitate a recalculation of previous years' emission estimates, and the impact of the recalculation on the emission estimates, if applicable.

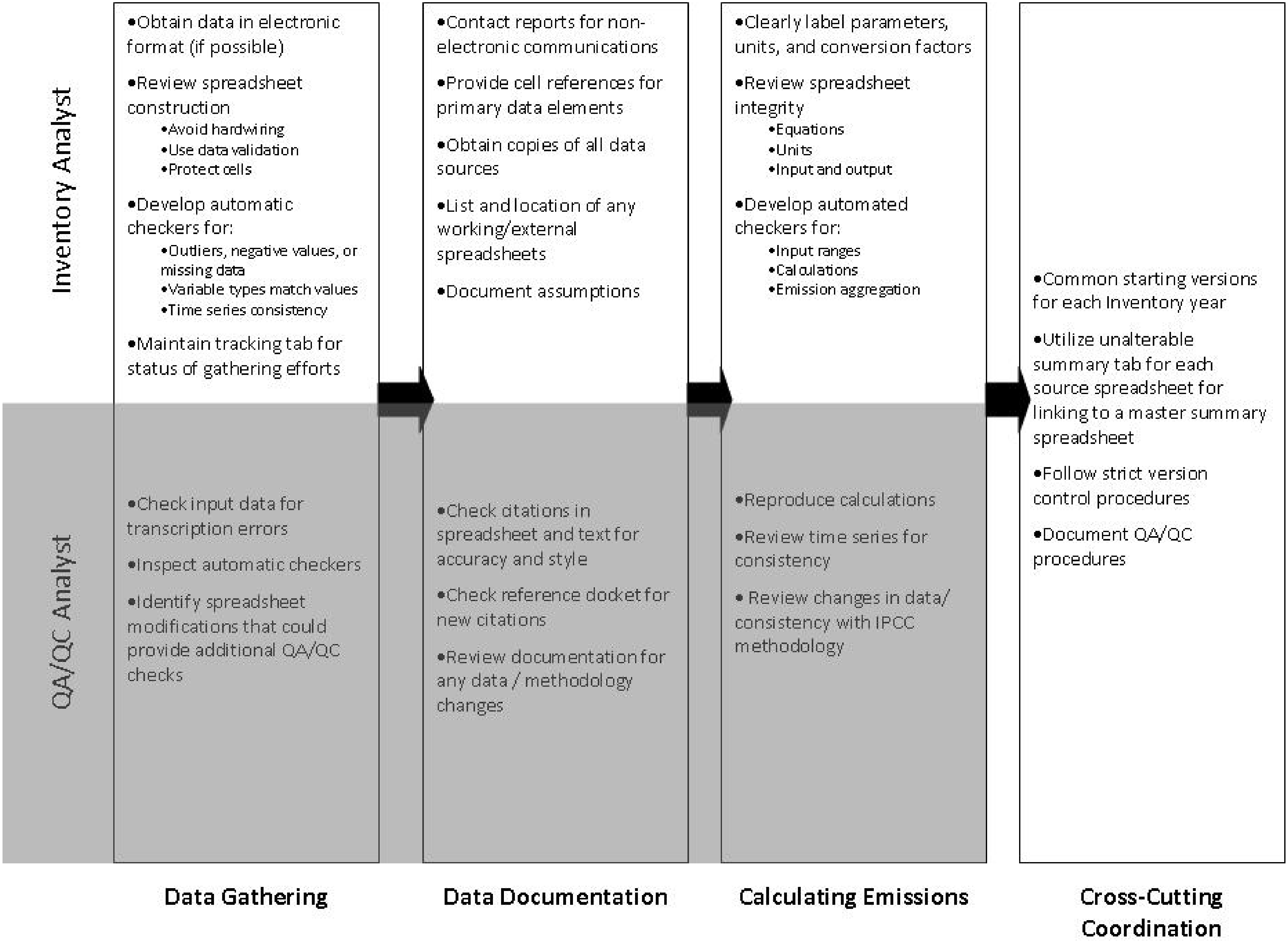
Planned Improvements: A discussion on any source-specific planned improvements, if applicable.

Special attention is given to CO_2 from fossil fuel combustion relative to other sources because of its share of emissions and its dominant influence on emission trends. For example, each energy consuming end-use sector (i.e., residential, commercial, industrial, and transportation), as well as the electricity generation sector, is described individually. Additional information for certain source categories and other topics is also provided in several Annexes listed in Table 1-7.

Table 1-7: List of Annexes

ANNEX 1 Key Category Analysis
ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion
2.1. Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion
2.2. Methodology for Estimating the Carbon Content of Fossil Fuels
2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels
ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories
3.1. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Stationary Combustion
3.2. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions
3.3. Methodology for Estimating CH_4 Emissions from Coal Mining
3.4. Methodology for Estimating CH_4 Emissions from Natural Gas Systems
3.5. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems
3.6. Methodology for Estimating CO_2 and N_2O Emissions from Incineration of Waste
3.7. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military
3.8. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances
3.9. Methodology for Estimating CH_4 Emissions from Enteric Fermentation
3.10. Methodology for Estimating CH_4 and N_2O Emissions from Manure Management
3.11. Methodology for Estimating N_2O Emissions from Agricultural Soil Management
3.12. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands
3.13. Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils on Croplands and Grasslands
3.14. Methodology for Estimating CH_4 Emissions from Landfills
ANNEX 4 IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion
ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included
ANNEX 6 Additional Information
6.1. Global Warming Potential Values
6.2. Ozone Depleting Substance Emissions
6.3. Sulfur Dioxide Emissions
6.4. Complete List of Source Categories
6.5. Constants, Units, and Conversions
6.6. Abbreviations

Figure 1: U.S. QA/QC Plan Summary



	Data Gathering	Data Documentation	Calculating Emissions	Cross-Cutting Coordination

Inventory Analyst	•Obtain data in electronic format (if possible)
	•Review spreadsheet construction
	  •Avoid hardwiring
	  •Use data validation
	  •Protect cells
	•Develop automatic checkers for:
	  •Outliers, negative values, or missing data
	  •Variable types match values
	  •Time series consistency
	•Maintain tracking tab for status of gathering efforts
		•Contact reports for non-electronic communications
		•Provide cell references for primary data elements
		•Obtain copies of all data sources
		•List and location of any working/external spreadsheets
		•Document assumptions
			•Clearly label parameters, units, and conversion factors
			•Review spreadsheet integrity
			  •Equations
			  •Units
			  •Input and output
			•Develop automated checkers for:
			  •Input ranges
			  •Calculations
			  •Emission aggregation
				•Common starting versions for each Inventory year
				•Utilize unalterable summary tab for each source spreadsheet for linking to a master summary spreadsheet
				•Follow strict version control procedures
				•Document QA/QC procedures

QA/QC Analyst	•Check input data for transcription errors •Inspect automatic checkers •Identify spreadsheet modifications that could provide additional QA/QC checks	•Check citations in spreadsheet and text for accuracy and style •Check reference docket for new citations •Review documentation for any data / methodology changes	•Reproduce calculations •Review time series for consistency • Review changes in data/ consistency with IPCC methodology	

2. Trends in Greenhouse Gas Emissions

2.1. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2009, total U.S. greenhouse gas emissions were 6,633.2 teragrams of carbon dioxide equivalents (Tg CO_2 Eq.); net emissions were 5,618.2 Tg CO_2 Eq. reflecting the influence of sinks (net CO_2 flux from Land Use, Land Use Change, and Forestry).[44] While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). The following factors were primary contributors to this decrease: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly.

Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

As the largest contributor to U.S. greenhouse gas emissions, carbon dioxide (CO_2) from fossil fuel combustion has accounted for approximately 79 percent of global warming potential (GWP) weighted emissions since 1990, from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions from this source category grew by 9.9 percent (470.6 Tg CO_2 Eq.) from 1990 to 2009 and were responsible for most of the increase in national emissions during this period. From 2008 to 2009, these emissions decreased by 6.4 percent (356.9 Tg CO_2 Eq.). Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends.

Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. On an annual basis, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than in a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

In the longer-term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Energy-related CO_2 emissions also depend on the type of fuel or energy consumed and its carbon (C) intensity. Producing a unit of heat or electricity using natural gas instead of coal, for example, can reduce the CO_2 emissions because of the lower C content of natural gas.

A brief discussion of the year to year variability in fuel combustion emissions is provided below, beginning with 2005.

From 2005 to 2006, emissions from fuel combustion decreased for the first time since 2000 to 2001. This decrease occurred across all sectors, with the exception of the industrial sector and the U.S. Territories sector, due to a

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[44] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

number of factors. The decrease in emissions from electricity generation is a result of a smaller share of electricity generated by coal and a greater share generated by natural gas. Coal consumption for electricity generation decreased by 1.3 percent while natural gas consumption for electricity generation increased by 6.0 percent in 2006 and nuclear power generation increased by less than 1 percent. The decrease in consumption of transportation fuels is primarily a result of the restraint on fuel consumption caused by rising fuel prices, which directly resulted in a decrease of petroleum consumption within this sector of about 1.1 percent in 2006. The significant decrease in emissions from the residential sector is primarily a result of decreased electricity consumption due to increases in the price of electricity, and warmer winter weather conditions compared to 2005. A moderate increase in industrial sector emissions is the result of growth in industrial output and growth in the U.S. economy. Renewable fuels used to generate electricity increased in 2006, with the greatest growth occurring in generation from wind by 48 percent.

After experiencing a decrease from 2005 to 2006, emissions from fuel combustion grew from 2006 to 2007 at a rate somewhat higher than the average growth rate since 1990. There were a number of factors contributing to this increase. More energy-intensive weather conditions in both the winter and summer resulted in an increase in consumption of heating fuels, as well as an increase in the demand for electricity. This demand for electricity was met with an increase in coal consumption of 1.7 percent, and with an increase in natural gas consumption of 9.9 percent. This increase in fossil fuel consumption, combined with a 14.7 percent decrease in hydropower generation from 2006 to 2007, resulted in an increase in emissions in 2007. The increase in emissions from the residential and commercial sectors is a result of increased electricity consumption due to warmer summer conditions and cooler winter conditions compared to 2006. In addition to these more energy-intensive weather conditions, electricity prices remained relatively stable compared to 2006, and natural gas prices decreased slightly. Emissions from the industrial sector decreased compared to 2006 as a result of a decrease in industrial production and fossil fuels used for electricity generation. Despite an overall decrease in electricity generation from renewable energy in 2007 driven by decreases in hydropower generation, wind and solar generation increased significantly.

Emissions from fossil fuel combustion decreased from 2007 to 2008. Several factors contributed to this decrease in emissions. An increase in energy prices coupled with the economic downturn led to a decrease in energy demand and a resulting decrease in emissions from 2007 to 2008. In 2008, the price of coal, natural gas, and petroleum used to generate electricity, as well as the price of fuels used for transportation, increased significantly. As a result of this price increase, coal, natural gas, and petroleum consumption used for electricity generation decreased by 1.4 percent, 2.5 percent, and 28.8 percent, respectively. The increase in the cost of fuels to generate electricity translated into an increase in the price of electricity, leading to a decrease in electricity consumption across all sectors except the commercial sector. The increase in transportation fuel prices led to a decrease in vehicle miles traveled (VMT) and a 5.5 percent decrease in transportation fossil fuel combustion emissions from 2007 to 2008. Cooler weather conditions in the summer led to a decrease in cooling degree days by 8.7 percent and a decrease in electricity demand compared to 2007, whereas cooler winter conditions led to a 5.6 percent increase in heating degree days compared to 2007 and a resulting increase in demand for heating fuels. The increased emissions from winter heating energy demand was offset by a decrease in emissions from summer cooling related electricity demand. Lastly, renewable energy[45] consumption for electricity generation increased by 9.6 percent from 2007 to 2008, driven by a significant increase in solar and wind energy consumption (of 19.4 percent and 60.2 percent, respectively). This increase in renewable energy generation contributed to a decrease in the carbon intensity of electricity generation.

From 2008 to 2009, CO_2 from fossil fuel combustion emissions experienced a decrease of 6.4 percent, the greatest decrease of any year over the course of the twenty-year period. Various factors contributed to this decrease in emissions. The continued economic downturn resulted in a 2.6 percent decrease in GDP, and a decrease in energy consumption across all sectors. The economic downturn also impacted total industrial production and manufacturing output, which decreased by 9.3 and 10.9 percent, respectively. In 2009, the price of coal used to generate electricity increased, while the price of natural gas used to generate electricity decreased significantly. As a result, natural gas was used for a greater share of electricity generation in 2009 than 2008, and coal was used for a smaller share. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 6.8 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. From 2008 to 2009, industrial sector emissions decreased significantly as a result of a decrease in output from energy-intensive industries of 16.6

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[45] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

percent in nonmetallic mineral and 31.6 percent in primary metal industries. The residential and commercial sectors only experienced minor decreases in emissions as summer and winter weather conditions were less energy-intensive from 2008 to 2009, and the price of electricity only increased slightly. Heating degree days decreased slightly and cooling degree days decreased by 3.8 percent from 2008 to 2009.

Overall, from 1990 to 2009, total emissions of CO_2 and CH_4 increased by 405.5 Tg CO_2 Eq. (8.0 percent) and 11.4 Tg CO_2 Eq. (1.7 percent), respectively, while N_2O emissions decreased by 19.6 Tg CO_2 Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 54.1 Tg CO_2 Eq. (58.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of them have extremely high GWPs and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by C sequestration in managed forests, trees in urban areas, agricultural soils, and landfilled yard trimmings. These were estimated to offset 15.3 percent of total emissions in 2009.

Table 2-1 summarizes emissions and sinks from all U.S. anthropogenic sources in weighted units of Tg CO_2 Eq., while unweighted gas emissions and sinks in gigagrams (Gg) are provided in Table 2-2.

Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**5,099.7**	**5,975.0**	**6,113.8**	**6,021.1**	**6,120.0**	**5,921.4**	**5,505.2**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	*1,820.8*	*2,296.9*	*2,402.1*	*2,346.4*	*2,412.8*	*2,360.9*	*2,154.0*
Transportation	*1,485.9*	*1,809.5*	*1,896.6*	*1,878.1*	*1,894.0*	*1,789.9*	*1,719.7*
Industrial	*846.5*	*851.1*	*823.1*	*848.2*	*842.0*	*802.9*	*730.4*
Residential	*338.3*	*370.7*	*357.9*	*321.5*	*342.4*	*348.2*	*339.2*
Commercial	*219.0*	*230.8*	*223.5*	*208.6*	*219.4*	*224.2*	*224.0*
U.S. Territories	*27.9*	*35.9*	*50.0*	*50.3*	*46.1*	*39.8*	*41.7*
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861.5)*	*(576.6)*	*(1,056.5)*	*(1,064.3)*	*(1,060.9)*	*(1,040.5)*	*(1,015.1)*
Biomass—Wood[b]	215.2	218.1	206.9	203.8	203.3	198.4	183.8
International Bunker Fuels[c]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*

Biomass—Ethanol[b]	4.2	9.4	23.0	31.0	38.9	54.8	61.2
CH_4	**674.9**	**659.9**	**631.4**	**672.1**	**664.6**	**676.7**	**686.3**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agriculture Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**315.2**	**341.0**	**322.9**	**326.4**	**325.1**	**310.8**	**295.6**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[d]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**

Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**5,099,719**	**5,974,991**	**6,113,751**	**6,021,089**	**6,120,009**	**5,921,443**	**5,505,204**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Electricity Generation	*1,820,818*	*2,296,894*	*2,402,142*	*2,346,406*	*2,412,827*	*2,360,919*	*2,154,025*
Transportation	*1,485,937*	*1,809,514*	*1,896,606*	*1,878,125*	*1,893,994*	*1,789,918*	*1,719,685*
Industrial	*846,475*	*851,094*	*823,069*	*848,206*	*842,048*	*802,856*	*730,422*
Residential	*338,347*	*370,666*	*357,903*	*321,513*	*342,397*	*348,221*	*339,203*
Commercial	*218,964*	*230,828*	*223,512*	*208,582*	*219,356*	*224,167*	*223,993*
U.S. Territories	*27,882*	*35,853*	*49,968*	*50,284*	*46,123*	*39,845*	*41,652*
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Iron and Steel Production & Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Ammonia Production and Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Cropland Remaining Cropland	7,084	7,541	7,854	7,875	8,202	8,654	7,832
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Wetlands Remaining Wetlands	1,033	1,227	1,079	879	1,012	992	1,090
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966

Lead Production	516	594	553	560	562	551	525
Petroleum Systems	555	534	490	488	474	453	463
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(861,535)*	*(576,588)*	*(1,056,459)*	*(1,064,330)*	*(1,060,882)*	*(1,040,461)*	*(1,015,074)*
Biomass - Wood[b]	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
International Bunker Fuels[c]	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
Biomass - Ethanol[b]	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**32,136**	**31,423**	**30,069**	**32,004**	**31,647**	**32,225**	**32,680**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Forest Land Remaining Forest Land	152	682	467	1,027	953	569	372
Rice Cultivation	339	357	326	282	295	343	349
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Composting	15	60	75	75	79	80	79
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production & Metallurgical Coke Production	46	44	34	35	33	31	17
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[c]	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**1,017**	**1,100**	**1,042**	**1,053**	**1,049**	**1,002**	**954**
Agricultural Soil Management	638	667	682	674	675	680	660
Mobile Combustion	142	172	119	108	98	84	77
Manure Management	47	55	56	58	58	58	58
Nitric Acid Production	57	63	53	52	62	53	47
Stationary Combustion	41	47	47	47	47	46	41
Forest Land Remaining Forest Land	9	39	27	58	54	33	22
Wastewater Treatment	12	14	15	16	16	16	16
N_2O from Product Uses	14	16	14	14	14	14	14
Adipic Acid Production	51	18	16	14	12	7	6
Composting	1	4	6	6	6	6	6
Settlements Remaining Settlements	3	4	5	5	5	5	5

Incineration of Waste	2	1	1	1	1	1	1
Field Burning of Agricultural Residues	+	+	+	+	+	+	+
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*3*	*3*	*3*	*4*	*4*	*4*	*4*
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[d]	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacture	+	+	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Semiconductor Manufacture	M	M	M	M	M	M	M
Aluminum Production	M	M	M	M	M	M	M
SF_6	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Magnesium Production and Processing	+	+	+	+	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

M Mixture of multiple gases

[a] The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Emissions of all gases can be summed from each source category from Intergovernmental Panel on Climate Change (IPCC) guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO_2 Eq. (8.8 percent) and 35.7 Tg CO_2 Eq. (9.3 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO_2 Eq. (10.4 percent), 24.7 Tg CO_2 Eq. (14.1 percent) and less than 0.1 Tg CO_2 Eq. (less than 0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector increased by 153.5 Tg CO_2 Eq. (17.8 percent).

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg CO_2 Eq.)

Chapter/IPCC Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5

Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**
Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Sinks)*	(861.5)	(576.6)	(1056.5)	(1064.3)	(1060.9)	(1040.5)	(1015.1)
Net Emissions (Sources and Sinks)	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Please refer to Table 2-9 for a breakout by source.

Note: Totals may not sum due to independent rounding.

Note: Parentheses indicate negative values or sequestration.

Energy

Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure 2-5 and Figure 2-6). A discussion of specific trends related to CO_2 as well as other greenhouse gas emissions from energy consumption is presented in the Energy chapter. Energy-related activities are also responsible for CH_4 and N_2O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Table 2-4 presents greenhouse gas emissions from the Energy chapter, by source and gas.

Figure 2-5: 2009 Energy Chapter Greenhouse Gas Sources

Figure 2-6: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Table 2-4: Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood[a]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[b]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass - Ethanol[a]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+

International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
International Bunker Fuels[b]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry

[b] Emissions from International Bunker Fuels are not included in totals.

Note: Totals may not sum due to independent rounding.

Carbon dioxide emissions from fossil fuel combustion are presented in Table 2-5 based on the underlying U.S. energy consumer data collected by EIA. Estimates of CO_2 emissions from fossil fuel combustion are calculated from these EIA "end-use sectors" based on total consumption and appropriate fuel properties (any additional analysis and refinement of the EIA data is further explained in the Energy chapter of this report). EIA's fuel consumption data for the electric power sector comprises electricity-only and combined-heat-and-power (CHP) plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public (nonutility power producers can be included in this sector as long as they meet they electric power sector definition). EIA statistics for the industrial sector include fossil fuel consumption that occurs in the fields of manufacturing, agriculture, mining, and construction. EIA's fuel consumption data for the transportation sector consists of all vehicles whose primary purpose is transporting people and/or goods from one physical location to another. EIA's fuel consumption data for the industrial sector consists of all facilities and equipment used for producing, processing, or assembling goods (EIA includes generators that produce electricity and/or useful thermal output primarily to support on-site industrial activities in this sector). EIA's fuel consumption data for the residential sector consists of living quarters for private households. EIA's fuel consumption data for the commercial sector consists of service-providing facilities and equipment from private and public organizations and businesses (EIA includes generators that produce electricity and/or useful thermal output primarily to support the activities at commercial establishments in this sector). Table 2-5, Figure 2-7, and Figure 2-8 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table 2-5: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Transportation	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	**1,533.2**	**1,640.8**	**1,560.0**	**1,560.2**	**1,572.0**	**1,517.7**	**1,333.7**
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	**931.4**	**1,133.1**	**1,214.7**	**1,152.4**	**1,198.5**	**1,182.2**	**1,123.8**
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	**757.0**	**972.1**	**1,027.2**	**1,007.6**	**1,041.1**	**1,031.6**	**985.7**
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Figure 2-7: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

The main driver of emissions in the Energy sector is CO_2 from fossil fuel combustion. The transportation end-use sector accounted for 1,724.1 Tg CO_2 Eq. in 2009 or approximately 33 percent of total CO_2 emissions from fossil fuel combustion, the largest share of any end-use sector.[46] The industrial end-use sector accounted for 26 percent of CO_2 emissions from fossil fuel combustion. The residential and commercial end-use sectors accounted for an average 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing 70 and 77 percent of emissions from the residential and commercial end-use sectors, respectively. Significant trends in emissions from energy source categories over the twenty-year period from 1990 through 2009 included the following:

- Total CO_2 emissions from fossil fuel combustion increased from 4,738.4 Tg CO_2 Eq. to 5,209.0 Tg CO_2 Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO_2 Eq. (6.4 percent), the largest decrease of any year over the twenty-year period.
- CO_2 emissions from non-energy use of fossil fuels increased 4.7 Tg CO_2 Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq. in 2009, which constituted 2.2 percent of total national CO_2 emissions.
- CO_2 emissions from incineration of waste (12.3 Tg CO_2 Eq. in 2009) increased by 4.3 Tg CO_2 Eq. (54 percent) from 1990 through 2009, as the volume of plastics and other fossil carbon-containing materials in municipal solid waste grew.
- CH_4 emissions from coal mining were 71.0 Tg CO_2 Eq. in 2009, a decline in emissions of 13.0 Tg CO_2 Eq. (15.5 percent) from 1990. This occurred as a result of the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- CH_4 emissions from natural gas systems were 221.2 Tg CO_2 Eq. in 2009; emissions have increased by 31.4 Tg CO_2 Eq. (16.6 percent) since 1990.
- In 2009, N_2O emissions from mobile combustion were 23.9 Tg CO_2 Eq. (approximately 8.1 percent of U.S. N_2O emissions). From 1990 to 2009, N_2O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 26 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to a steady decline in N_2O from this source.

Industrial Processes

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production (see Figure 2-9). Industrial processes also release HFCs, PFCs and SF_6. In addition to their use as ODS substitutes, HFCs, PFCs, SF_6, and other fluorinated compounds are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Table 2-6 presents greenhouse gas emissions from industrial processes by source category.

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[46] Note that electricity generation is the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

Table 2-6: Emissions from Industrial Processes (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188.4**	**184.9**	**165.4**	**169.9**	**172.6**	**159.5**	**119.0**
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Iron and Steel Production	*97.1*	*83.7*	*63.9*	*66.9*	*69.0*	*63.7*	*40.9*
Metallurgical Coke Production	*2.5*	*2.2*	*2.0*	*1.9*	*2.1*	*2.3*	*1.0*
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	**1.9**	**2.2**	**1.8**	**1.7**	**1.7**	**1.6**	**1.2**
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Iron and Steel Production	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.4*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N_2O	**33.5**	**24.9**	**21.5**	**20.5**	**22.9**	**18.5**	**16.5**
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	**36.9**	**103.2**	**120.2**	**123.4**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[a]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	**315.8**	**348.8**	**334.1**	**339.4**	**350.9**	**331.7**	**282.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Overall, emissions from industrial processes decreased by 10.4 percent from 1990 to 2009 due to decreases in emissions from several industrial processes, such as iron and steel production and metallurgical coke production, HCFC-22 production, aluminum production, adipic acid production, and electrical transmission and distribution. Significant trends in emissions from industrial processes source categories over the twenty-year period from 1990 through 2009 included the following:

- Combined CO_2 and CH_4 emissions from iron and steel production and metallurgical coke production decreased by 36.6 percent to 42.2 Tg CO_2 Eq. from 2008 to 2009, and have declined overall by 58.2 Tg CO_2 Eq. (58.0 percent) from 1990 through 2009, due to restructuring of the industry, technological improvements, and increased scrap utilization.
- CO_2 emissions from ammonia production and urea consumption (11.8 Tg CO_2 Eq. in 2009) have decreased by 5.0 Tg CO_2 Eq. (29.9 percent) since 1990, due to a decrease in domestic ammonia production. This decrease in ammonia production is primarily attributed to market fluctuations.
- N_2O emissions from adipic acid production were 1.9 Tg CO_2 Eq. in 2009, and have decreased significantly in recent years from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990 and by 89.0 percent since a peak in 1995.
- HFC emissions from ODS substitutes have been increasing from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. This increase results from efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely accelerate over the next decade as HCFCs—which are interim substitutes in many applications—are phased out under the provisions of the Copenhagen Amendments to the Montreal Protocol.
- PFC emissions from aluminum production decreased by about 91.5 percent (17.0 Tg CO_2 Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, N_2O Emissions from Product Uses, the only source of greenhouse gas emissions from this sector, accounted for 4.4 Tg CO_2 Eq., or less than 0.1 percent of total U.S. emissions in 2009 (see Table 2-7).

Table 2-7: N_2O Emissions from Solvent and Other Product Use (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
N_2O	**4.4**	**4.9**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Total	**4.4**	**4.9**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**

In 2009, N_2O emissions from product uses constituted 1.5 percent of U.S. N_2O emissions. From 1990 to 2009, emissions from this source category decreased by just under 0.4 percent, though slight increases occurred in intermediate years.

Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues.

In 2009, agricultural activities were responsible for emissions of 419.3 Tg CO_2 Eq., or 6.3 percent of total U.S. greenhouse gas emissions. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented about 20.4 percent and 7.2 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities, such as fertilizer application and other cropping practices, were the largest source of U.S. N_2O emissions in 2009, accounting for 69.2 percent.

Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

Table 2-8: Emissions from Agriculture (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**186.7**	**190.1**	**191.7**	**198.2**	**197.5**	**196.8**
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N_2O	**212.4**	**224.0**	**228.7**	**227.1**	**227.6**	**228.8**	**222.5**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**383.6**	**410.6**	**418.8**	**418.8**	**425.8**	**426.3**	**419.3**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Agriculture include the following:

- Agricultural soils produced approximately 69 percent of N_2O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990. Nitrous oxide emissions from this source have not shown any significant long-term trend, as their estimation is highly sensitive to the amount of N applied to soils, which has not changed significantly over the time-period, and to weather patterns and crop type.

- Enteric fermentation was the largest source of CH_4 emissions in 2009, at 139.8 Tg CO_2 Eq. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations increased and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations decreased again. During the timeframe of this analysis, populations of sheep have decreased 49 percent since 1990 while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.

- Overall, emissions from manure management increased 46 percent between 1990 and 2009. This encompassed an increase of 56 percent for CH_4, from 31.7 Tg CO_2 Eq. in 1990 to 49.5 Tg CO_2 Eq. in 2009; and an increase of 23 percent for N_2O, from 14.5 Tg CO_2 Eq. in 1990 to 17.9 Tg CO_2 Eq. in 2009. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions.

Land Use, Land-Use Change, and Forestry

When humans alter the terrestrial biosphere through land use, changes in land use, and land management practices, they also alter the background carbon fluxes between biomass, soils, and the atmosphere. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps have resulted in an uptake (sequestration) of carbon in the United States, which offset about 15 percent of total U.S. greenhouse gas emissions in 2009. Forests (including vegetation, soils, and harvested wood) accounted for approximately 85 percent of total 2009 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. The net forest sequestration is a result of net forest growth, increasing forest area, and a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth and increased urban forest size. In agricultural soils, mineral and organic soils sequester approximately 5.5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to hay production fields, the limited use of bare-summer fallow areas in semi-arid areas, and an increase in the adoption of conservation tillage practices. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (276.8 Tg C) (Table 2-9). This represents an offset of approximately 18 percent of total U.S. CO_2 emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO_2 sequestration.

Table 2-9: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Land use, land-use change, and forestry source categories also resulted in emissions of CO_2, CH_4, and N_2O that are not included in the net CO_2 flux estimates presented in Table 2-9. The application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization resulted in CO_2 emissions of 7.8 Tg CO_2 Eq. in 2009, an increase of about 10.6 percent relative to 1990. Lands undergoing peat extraction resulted in CO_2 emissions of 1.1 Tg CO_2 Eq. (1,090 Gg), and N_2O emissions of less than 0.01 Tg CO_2 Eq. N_2O emissions from the application of synthetic fertilizers to forest soils have increased from 0.1 Tg CO_2 Eq. in 1990 to 0.4 Tg CO_2 Eq. in 2009. Settlement soils in 2009 resulted in direct N_2O emissions of 1.5 Tg CO_2 Eq., a 55 percent increase relative to 1990. Emissions from forest fires in 2009 resulted in CH_4 emissions of 7.8 Tg CO_2 Eq., and in N_2O emissions of 6.4 Tg CO_2 Eq. (Table 2-10).

Table 2-10: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Other significant trends from 1990 to 2009 in land use, land-use change, and forestry emissions include:

- Net C sequestration by forest land has increased by almost 27 percent. This is primarily due to increased forest management and the effects of previous reforestation. The increase in intensive forest management resulted in higher growth rates and higher biomass density. The tree planting and conservation efforts of the 1970s and 1980s continue to have a significant impact on sequestration rates. Finally, the forested area in the United States increased over the past 20 years, although only at an average rate of 0.21 percent per year.
- Net sequestration of C by urban trees has increased by 68 percent over the period from 1990 to 2009. This is primarily due to an increase in urbanized land area in the United States.
- Annual C sequestration in landfilled yard trimmings and food scraps has decreased by 48 percent since 1990. This is due in part to a decrease in the amount of yard trimmings and food scraps generated. In addition, the proportion of yard trimmings and food scraps landfilled has decreased, as there has been a significant rise in the number of municipal composting facilities in the United States.

Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 2-11). In 2009, landfills were the third largest source of anthropogenic CH_4 emissions, accounting for 17 percent of total U.S. CH_4 emissions.[47] Additionally, wastewater treatment accounts for 4 percent of U.S. CH_4 emissions, and 2 percent of N_2O emissions. Emissions of CH_4 and N_2O from composting grew from 1990 to 2009, and resulted in emissions of 3.5 Tg CO_2 Eq. in 2009. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 2-11.

Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO_2 Eq., or 2.3 percent of total U.S. greenhouse gas emissions.

Table 2-11: Emissions from Waste (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH_4	**171.2**	**138.1**	**138.4**	**137.8**	**137.4**	**142.1**	**143.6**
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	**4.0**	**5.9**	**6.5**	**6.6**	**6.7**	**6.8**	**6.9**
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**175.2**	**143.9**	**144.9**	**144.4**	**144.1**	**149.0**	**150.5**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Waste include the following:

- Combined CO_2 and CH_4 emissions from composting have generally increased since 1990, from 0.7 Tg CO_2 Eq. to 3.5 Tg CO_2 Eq. in 2009, an over four-fold increase over the time series.
- From 1990 to 2009, net CH_4 emissions from landfills decreased by 29.9 Tg CO_2 Eq. (20 percent), with small increases occurring in interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,[48] which has more than offset the

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[47] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land Use, Land-Use Change, and Forestry chapter.

[48] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- From 1990 to 2009, CH_4 and N_2O emissions from wastewater treatment increased by 1.0 Tg CO_2 Eq. (4.4 percent) and 1.3 Tg CO_2 Eq. (36 percent), respectively.

2.2. Emissions by Economic Sector

Throughout this report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC and detailed above: Energy; Industrial Processes; Solvent and Other Product Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following U.S. economic sectors: residential, commercial, industry, transportation, electricity generation, and agriculture, as well as U.S. territories.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent). Emissions from industry accounted for about 20 percent of U.S. greenhouse gas emissions in 2009. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements. The remaining 20 percent of U.S. greenhouse gas emissions were contributed by the residential, agriculture, and commercial sectors, plus emissions from U.S. territories. The residential sector accounted for 5 percent, and primarily consisted of CO_2 emissions from fossil fuel combustion. Activities related to agriculture accounted for roughly 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation, rather than CO_2 from fossil fuel combustion. The commercial sector accounted for roughly 6 percent of emissions, while U.S. territories accounted for less than 1 percent.

CO_2 was also emitted and sequestered (in the form of C) by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Table 2-12 presents a detailed breakdown of emissions from each of these economic sectors by source category, as they are defined in this report. Figure 2-12 shows the trend in emissions by sector from 1990 to 2009.

Figure 2-12: Emissions Allocated to Economic Sectors

Table 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg CO_2 Eq. and Percent of Total in 2009)

Sector/Source	1990	2000	2005	2006	2007	2008	2009	Percent[a]
Electric Power Industry	**1,868.9**	**2,337.6**	**2,444.6**	**2,388.2**	**2,454.0**	**2,400.7**	**2,193.0**	**33.1%**
CO_2 from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0	32.5%
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8	0.2%
Incineration of Waste	8.5	11.5	12.9	12.9	13.1	12.5	12.7	0.2%
Stationary Combustion	8.6	10.6	11.0	10.8	11.0	10.8	9.7	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Transportation	**1,545.2**	**1,932.3**	**2,017.4**	**1,994.4**	**2,003.8**	**1,890.7**	**1,812.4**	**27.3%**
CO_2 from Fossil Fuel Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7	25.9%
Substitution of Ozone Depleting Substances	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Mobile Combustion	47.4	55.1	37.7	34.2	30.7	26.4	24.0	0.4%
Non-Energy Use of Fuels	11.8	12.1	10.2	9.9	10.2	9.5	8.5	0.1%
Industry	**1,564.4**	**1,544.0**	**1,441.9**	**1,497.3**	**1,483.0**	**1,446.9**	**1,322.7**	**19.9%**
CO_2 from Fossil Fuel Combustion	815.4	812.3	776.3	799.2	793.6	757.4	683.8	10.3%

Natural Gas Systems	227.4	239.2	220.4	248.4	236.2	244.6	253.4	3.8%
Non-Energy Use of Fuels	101.1	122.8	125.2	126.8	119.8	123.1	111.1	1.7%
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0	1.1%
Iron and Steel Production & Metallurgical Coke Production	100.5	86.9	66.6	69.5	71.7	66.7	42.2	0.6%
Petroleum Systems	35.9	32.0	29.9	29.8	30.4	30.7	31.4	0.5%
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0	0.4%
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6	0.2%
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8	0.2%
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2	0.2%
Substitution of Ozone Depleting Substances	+	3.2	6.4	7.1	7.8	8.5	10.9	0.2%
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5	0.1%
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4	0.1%
Semiconductor Manufacture	2.9	6.2	4.4	4.7	4.8	5.1	5.3	0.1%
Aluminum Production	25.4	14.7	7.1	6.3	8.1	7.2	4.6	0.1%
N_2O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4	0.1%
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Stationary Combustion	4.7	4.8	4.4	4.6	4.4	4.1	3.6	0.1%
Petrochemical Production	4.2	5.7	5.3	4.8	4.9	4.4	3.6	0.1%
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9	+
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8	+
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5	+
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5	+
Mobile Combustion	0.9	1.1	1.3	1.3	1.3	1.3	1.3	+
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1	+
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0	+
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0	+
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5	+
Silicon Carbide Production and Consumption	0.4	0.3	0.2	0.2	0.2	0.2	0.2	+
Agriculture	**429.0**	**485.1**	**493.2**	**516.7**	**520.7**	**503.9**	**490.0**	**7.4%**
N_2O from Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6	3.1%
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8	2.1%
Manure Management	46.2	59.5	63.8	64.8	68.9	67.3	67.3	1.0%
CO_2 from Fossil Fuel Combustion	31.04	38.79	46.81	49.04	48.44	45.44	46.66	0.7%
CH_4 and N_2O from Forest Fires	5.8	26.0	17.8	39.2	36.4	21.7	14.2	0.2%
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3	0.1%
Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2	0.1%
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6	0.1%
CO_2 and N_2O from Managed Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1	+
Mobile Combustion	0.3	0.4	0.5	0.5	0.5	0.5	0.5	+
N_2O from Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4	+
Field Burning of Agricultural Residues	0.4	0.4	0.3	0.3	0.3	0.4	0.4	+

Stationary Combustion	+	+	+	+	+	+	+	+
Commercial	**395.5**	**381.4**	**387.2**	**375.2**	**389.6**	**403.5**	**409.5**	**6.2%**
CO_2 from Fossil Fuel Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5	1.8%
Substitution of Ozone Depleting Substances	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5	0.4%
Human Sewage	3.7	4.5	4.8	4.8	4.9	5.0	5.0	0.1%
Composting	0.7	2.6	3.3	3.3	3.5	3.5	3.5	0.1%
Stationary Combustion	1.3	1.3	1.2	1.2	1.2	1.2	1.2	+
Residential	**345.1**	**386.2**	**371.0**	**335.8**	**358.9**	**367.1**	**360.1**	**5.4%**
CO_2 from Fossil Fuel Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
Substitution of Ozone Depleting Substances	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Stationary Combustion	5.5	4.3	4.3	3.9	4.2	4.4	4.2	0.1%
Settlement Soil Fertilization	1.0	1.1	1.5	1.5	1.6	1.5	1.5	+
U.S. Territories	**33.7**	**46.0**	**58.2**	**59.3**	**53.5**	**48.4**	**45.5**	**0.7%**
CO_2 from Fossil Fuel Combustion	27.9	35.9	50.0	50.3	46.1	39.8	41.7	0.6%
Non-Energy Use of Fuels	5.7	10.0	8.1	8.8	7.2	8.4	3.7	0.1%
Stationary Combustion	0.1	0.1	0.2	0.2	0.2	0.2	0.2	+
Total Emissions	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**100.0%**
Sinks	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**	**-15.3%**
CO_2 Flux from Forests[b]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)	-13.0%
Urban Trees	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	-1.4%
CO_2 Flux from Agricultural Soil Carbon Stocks	(99.2)	(107.6)	(45.6)	(46.1)	(46.3)	(44.4)	(43.4)	-0.7%
Landfilled Yard Trimmings and Food Scraps	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)	-0.2%
Net Emissions	**5,320.3**	**6,536.1**	**6,157.1**	**6,102.6**	**6,202.5**	**6,020.7**	**5,618.2**	**84.7%**

Note: Includes all emissions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Parentheses indicate negative values or sequestration. Totals may not sum due to independent rounding.

ODS (Ozone Depleting Substances)

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

[a] Percent of total emissions for year 2009.

[b] Includes the effects of net additions to stocks of carbon stored in harvested wood products.

Emissions with Electricity Distributed to Economic Sectors

It can also be useful to view greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). The generation, transmission, and distribution of electricity, which is the largest economic sector in the United States, accounted for 33 percent of total U.S. greenhouse gas emissions in 2009. Emissions increased by 17 percent since 1990, as electricity demand grew and fossil fuels remained the dominant energy source for generation. Electricity generation-related emissions decreased from 2008 to 2009 by 9 percent, primarily due to decreased CO_2 emissions from fossil fuel combustion. The decrease in electricity-related emissions was due to decreased economic output and the resulting decrease in electricity demand. Electricity-related emissions also declined due to a decrease in the carbon intensity of fuels used to generate electricity. This was caused by fuel switching as the price of coal increased and the price natural gas decreased significantly. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 7 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. The electricity generation sector in the United States is composed of traditional electric utilities as well as other entities, such as power marketers and non-utility power producers. The majority of electricity generated by these entities was through the combustion of coal in boilers to produce high-pressure steam that is passed through a turbine. Table 2-13 provides a detailed summary of emissions from electricity generation-related activities.

Table 2-13: Electricity Generation-Related Greenhouse Gas Emissions (Tg CO_2 Eq.)

Gas/Fuel Type or Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**1,831.4**	**2,310.5**	**2,418.0**	**2,363.0**	**2,429.4**	**2,376.2**	**2,170.1**
CO_2 from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Coal	*1,547.6*	*1,927.4*	*1,983.8*	*1,953.7*	*1,987.3*	*1,959.4*	*1,747.6*
Natural Gas	*175.3*	*280.8*	*318.8*	*338.0*	*371.3*	*361.9*	*373.1*
Petroleum	*97.5*	*88.4*	*99.2*	*54.4*	*53.9*	*39.2*	*32.9*
Geothermal	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8
CH_4	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Stationary Combustion*	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Incineration of Waste	+	+	+	+	+	+	+
N_2O	**8.5**	**10.4**	**10.7**	**10.5**	**10.6**	**10.4**	**9.4**
Stationary Combustion*	8.1	10.0	10.3	10.1	10.2	10.1	9.0
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
SF_6	**28.4**	**16.0**	**15.1**	**14.1**	**13.2**	**13.3**	**12.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Total	**1,868.9**	**2,337.6**	**2,444.6**	**2,388.2**	**2,454.0**	**2,400.7**	**2,193.0**

Note: Totals may not sum due to independent rounding.

* Includes only stationary combustion emissions related to the generation of electricity.

\+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

To distribute electricity emissions among economic end-use sectors, emissions from the source categories assigned to the electricity generation sector were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity (EIA 2010 and Duffield 2006). These three source categories include CO_2 from Fossil Fuel Combustion, CH_4 and N_2O from Stationary Combustion, and SF_6 from Electrical Transmission and Distribution Systems.[49]

When emissions from electricity are distributed among these sectors, industry activities account for the largest share of total U.S. greenhouse gas emissions (28.8 percent), followed closely by emissions from transportation (27.4 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included. In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Table 2-14 presents a detailed breakdown of emissions from each of these economic sectors, with emissions from electricity generation distributed to them. Figure 2-13 shows the trend in these emissions by sector from 1990 to 2009.

Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

Table 2-14: U.S Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (Tg CO_2 Eq.) and Percent of Total in 2009

Sector/Gas	1990	2000	2005	2006	2007	2008	2009	Percent[a]
Industry	**2,238.3**	**2,314.4**	**2,162.5**	**2,194.6**	**2,192.9**	**2,146.5**	**1,910.9**	**28.8%**
Direct Emissions	***1,564.4***	***1,544.0***	***1,441.9***	***1,497.3***	***1,483.0***	***1,446.9***	***1,322.7***	19.9%

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[49] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

CO_2	1,140.5	1,147.9	1,093.8	1,123.1	1,113.7	1,070.1	942.7	14.2%
CH_4	318.8	312.5	285.7	314.1	301.9	318.1	331.2	5.0%
N_2O	41.8	34.0	30.0	29.1	31.4	26.8	24.5	0.4%
HFCs, PFCs, and SF_6	63.3	49.6	32.5	31.0	36.0	31.9	24.2	0.4%
Electricity-Related	***673.9***	***770.4***	***720.5***	***697.3***	***709.9***	***699.7***	***588.3***	8.9%
CO_2	660.3	761.5	712.7	689.9	702.8	692.5	582.2	8.8%
CH_4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N_2O	3.1	3.4	3.2	3.1	3.1	3.0	2.5	+
SF_6	10.2	5.3	4.5	4.1	3.8	3.9	3.4	0.1%
Transportation	**1,548.3**	**1,935.8**	**2,022.2**	**1,999.0**	**2,008.9**	**1,895.5**	**1,816.9**	**27.4%**
Direct Emissions	***1,545.2***	***1,932.3***	***2,017.4***	***1,994.4***	***2,003.8***	***1,890.7***	***1,812.4***	27.3%
CO_2	1,497.8	1,821.6	1,906.8	1,888.0	1,904.2	1,799.4	1,728.2	26.1%
CH_4	4.5	3.1	2.2	2.0	1.9	1.7	1.6	+
N_2O	42.9	51.9	35.5	32.1	28.8	24.6	22.4	0.3%
HFCs[b]	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Electricity-Related	***3.1***	***3.5***	***4.8***	***4.6***	***5.1***	***4.7***	***4.5***	0.1%
CO_2	3.1	3.5	4.8	4.6	5.1	4.7	4.5	0.1%
CH_4	+	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+	+
SF_6	+	+	+	+	+	+	+	+
Commercial	**947.7**	**1,135.8**	**1,205.1**	**1,188.5**	**1,225.3**	**1,224.5**	**1,184.9**	**17.9%**
Direct Emissions	***395.5***	***381.4***	***387.2***	***375.2***	***389.6***	***403.5***	***409.5***	6.2%
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
CH_4	172.1	139.0	139.3	138.7	138.2	143.1	144.5	2.2%
N_2O	4.4	6.2	6.8	6.9	7.1	7.2	7.2	0.1%
HFCs	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Electricity-Related	***552.2***	***754.4***	***817.9***	***813.2***	***835.7***	***821.0***	***775.4***	11.7%
CO_2	541.1	745.7	809.0	804.7	827.4	812.7	767.4	11.6%
CH_4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N_2O	2.5	3.3	3.6	3.6	3.6	3.6	3.3	+
SF_6	8.4	5.2	5.1	4.8	4.5	4.6	4.5	0.1%
Residential	**953.8**	**1,162.2**	**1,242.9**	**1,181.5**	**1,229.6**	**1,215.1**	**1,158.9**	**17.5%**
Direct Emissions	***345.1***	***386.2***	***371.0***	***335.8***	***358.9***	***367.1***	***360.1***	5.4%
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4	0.1%
N_2O	2.1	2.1	2.4	2.3	2.4	2.4	2.4	+
HFCs	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Electricity-Related	***608.7***	***775.9***	***871.9***	***845.6***	***870.7***	***848.1***	***798.8***	12.0%
CO_2	596.5	767.0	862.4	836.7	862.0	839.4	790.5	11.9%
CH_4	0.2	0.2	0.3	0.3	0.3	0.2	0.2	+
N_2O	2.8	3.4	3.8	3.7	3.8	3.7	3.4	0.1%
SF_6	9.2	5.3	5.4	5.0	4.7	4.7	4.7	0.1%
Agriculture	**460.0**	**518.4**	**522.7**	**544.1**	**553.2**	**531.1**	**516.0**	**7.8%**
Direct Emissions	***429.0***	***485.1***	***493.2***	***516.7***	***520.7***	***503.9***	***490.0***	7.4%
CO_2	39.2	47.6	55.7	57.8	57.7	55.1	55.6	0.8%
CH_4	174.5	201.1	200.1	213.4	218.4	209.6	204.8	3.1%
N_2O	215.3	236.4	237.4	245.4	244.7	239.2	229.7	3.5%
Electricity-Related	***31.0***	***33.3***	***29.4***	***27.4***	***32.5***	***27.2***	***25.9***	0.4%
CO_2	30.4	32.9	29.1	27.1	32.2	26.9	25.7	0.4%
CH_4	+	+	+	+	+	+	+	+
N_2O	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
SF_6	0.5	0.2	0.2	0.2	0.2	0.2	0.2	+
U.S. Territories	**33.7**	**46.0**	**58.2**	**59.3**	**53.5**	**48.4**	**45.5**	**0.7%**
Total	**6,181.8**	**7,112.7**	**7,213.5**	**7,166.9**	**7,263.4**	**7,061.1**	**6,633.2**	**100.0%**

Note: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector. Totals may not sum due to independent rounding.

+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.
[a] Percent of total emissions for year 2009.
[b] Includes primarily HFC-134a.

Industry

The industrial end-use sector includes CO_2 emissions from fossil fuel combustion from all manufacturing facilities, in aggregate. This sector also includes emissions that are produced as a by-product of the non-energy-related industrial process activities. The variety of activities producing these non-energy-related emissions includes methane emissions from petroleum and natural gas systems, fugitive CH_4 emissions from coal mining, by-product CO_2 emissions from cement manufacture, and HFC, PFC, and SF_6 by-product emissions from semiconductor manufacture, to name a few. Since 1990, industrial sector emissions have declined. The decline has occurred both in direct emissions and indirect emissions associated with electricity use. However, the decline in direct emissions has been sharper. In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions. In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

Transportation

When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 27 percent of U.S. greenhouse gas emissions in 2009. The largest sources of transportation greenhouse gases in 2009 were passenger cars (35 percent), light duty trucks, which include sport utility vehicles, pickup trucks, and minivans (30 percent), freight trucks (20 percent) and commercial aircraft (6 percent). These figures include direct emissions from fossil fuel combustion, as well as HFC emissions from mobile air conditioners and refrigerated transport allocated to these vehicle types. Table 2-15 provides a detailed summary of greenhouse gas emissions from transportation-related activities with electricity-related emissions included in the totals.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Although average fuel economy over this period increased slightly due primarily to the retirement of older vehicles, average fuel economy among new vehicles sold annually gradually declined from 1990 to 2004. The decline in new vehicle fuel economy between 1990 and 2004 reflected the increasing market share of light duty trucks, which grew from about one-fifth of new vehicle sales in the 1970s to slightly over half of the market by 2004. Increasing fuel prices have since decreased the momentum of light duty truck sales, and average new vehicle fuel economy has improved since 2005 as the market share of passenger cars increased. VMT growth among all passenger vehicles has also been impacted, remaining stagnant from 2004 to 2007, compared to an average annual growth rate of 2.5 percent over the period 1990 to 2004. The recession supplemented the effect of increasing fuel prices in 2008 and VMT declined by 2.1 percent, the first decrease in annual passenger vehicle VMT since 1990. Overall, VMT grew by 0.2 percent in 2009. Gasoline fuel consumption increased slightly, while consumption of diesel fuel continued to decrease, due in part to a decrease in commercial activity and freight trucking as a result of the economic recession.

Table 2-15: Transportation-Related Greenhouse Gas Emissions (Tg CO_2 Eq.)

Gas/Vehicle Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Passenger Cars	**657.4**	**695.3**	**709.5**	**682.9**	**672.0**	**632.5**	**627.4**
CO_2	629.3	644.2	662.3	639.1	632.8	597.9	597.2
CH_4	2.6	1.6	1.1	1.0	0.9	0.8	0.7
N_2O	25.4	25.2	17.8	15.7	13.8	11.7	10.1
HFCs	+	24.3	28.4	27.1	24.6	22.1	19.3
Light-Duty Trucks	**336.6**	**512.1**	**551.3**	**564.0**	**570.3**	**553.8**	**551.0**
CO_2	321.1	467.0	505.9	519.5	528.4	515.1	514.5
CH_4	1.4	1.1	0.7	0.7	0.6	0.6	0.6
N_2O	14.1	22.4	13.7	12.6	11.2	9.5	9.4
HFCs	+	21.7	31.0	31.2	30.1	28.6	26.6
Medium- and Heavy-Duty Trucks	**231.1**	**354.6**	**408.4**	**418.6**	**425.2**	**403.1**	**365.6**
CO_2	230.1	345.8	396.0	406.1	412.5	390.4	353.1
CH_4	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.8	1.2	1.1	1.1	1.1	1.0	0.8
HFCs	+	7.4	11.1	11.4	11.5	11.6	11.6
Buses	**8.4**	**11.2**	**12.0**	**12.3**	**12.5**	**12.2**	**11.2**
CO_2	8.4	11.1	11.8	12.0	12.1	11.8	10.8
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
HFCs	+	0.1	0.2	0.3	0.3	0.4	0.4
Motorcycles	**1.8**	**1.9**	**1.7**	**1.9**	**2.1**	**2.2**	**2.2**
CO_2	1.7	1.8	1.6	1.9	2.1	2.1	2.1
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
Commercial Aircraft[a]	**136.8**	**170.9**	**162.8**	**138.5**	**139.5**	**123.4**	**112.5**
CO_2	135.4	169.2	161.2	137.1	138.1	122.2	111.4
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	1.3	1.6	1.5	1.3	1.3	1.2	1.1
Other Aircraft[b]	**44.4**	**33.5**	**35.9**	**35.1**	**33.2**	**35.2**	**29.6**
CO_2	43.9	33.1	35.5	34.7	32.8	34.8	29.3
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	+
N_2O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Ships and Boats[c]	**45.1**	**61.0**	**45.2**	**48.4**	**55.2**	**37.1**	**30.5**
CO_2	44.5	60.0	44.5	47.7	54.4	36.6	30.0
CH_4	+	+	+	+	+	+	+
N_2O	0.6	0.9	0.6	0.7	0.8	0.5	0.4
HFCs	+	0.1	+	+	+	+	+
Rail	**39.0**	**48.1**	**53.0**	**55.1**	**54.3**	**50.6**	**43.3**
CO_2	38.5	45.6	50.3	52.4	51.6	47.9	40.6
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.3	0.3	0.4	0.4	0.4	0.4	0.3
HFCs	+	2.0	2.2	2.2	2.2	2.3	2.3
Other Emissions from Electricity Generation[d]	0.1	+	0.1	0.1	0.1	0.1	0.1
Pipelines[e]	**36.0**	**35.2**	**32.2**	**32.3**	**34.3**	**35.7**	**35.2**
CO_2	36.0	35.2	32.2	32.3	34.3	35.7	35.2
Lubricants	**11.8**	**12.1**	**10.2**	**9.9**	**10.2**	**9.5**	**8.5**
CO_2	11.8	12.1	10.2	9.9	10.2	9.5	8.5
Total Transportation	**1,548.3**	**1,935.8**	**2,022.2**	**1,999.0**	**2,008.9**	**1,895.4**	**1,816.9**
International Bunker	*113.0*	*99.5*	*110.9*	*129.7*	*129.0*	*135.1*	*124.4*

Fuels[f]		

Note: Totals may not sum due to independent rounding. Passenger cars and light-duty trucks include vehicles typically used for personal travel and less than 8500 lbs; medium- and heavy-duty trucks include vehicles larger than 8500 lbs. HFC emissions primarily reflect HFC-134a.

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Consists of emissions from jet fuel consumed by domestic operations of commercial aircraft (no bunkers).

[b] Consists of emissions from jet fuel and aviation gasoline consumption by general aviation and military aircraft.

[c] Fluctuations in emission estimates are associated with fluctuations in reported fuel consumption, and may reflect data collection problems.

[d] Other emissions from electricity generation are a result of waste incineration (as the majority of municipal solid waste is combusted in “trash-to-steam” electricity generation plants), electrical transmission and distribution, and a portion of limestone and dolomite use (from pollution control equipment installed in electricity generation plants).

[e] CO_2 estimates reflect natural gas used to power pipelines, but not electricity. While the operation of pipelines produces CH_4 and N_2O, these emissions are not directly attributed to pipelines in the US Inventory.

[f] Emissions from International Bunker Fuels include emissions from both civilian and military activities; these emissions are not included in the transportation totals.

Commercial

The commercial sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Energy-related emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. Landfills and wastewater treatment are included in this sector, with landfill emissions decreasing since 1990 and wastewater treatment emissions increasing slightly.

Residential

The residential sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Emissions from the residential sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, this sector is also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Agriculture

The agriculture sector includes a variety of processes, including enteric fermentation in domestic livestock, livestock manure management, and agricultural soil management. In 2009, agricultural soil management was the largest source of N_2O emissions, and enteric fermentation was the second largest source of CH_4 emissions in the United States. This sector also includes small amounts of CO_2 emissions from fossil fuel combustion by motorized farm equipment like tractors. The agriculture sector relies less heavily on electricity than the other sectors.

[BEGIN BOX]

Box 2-1: Methodology for Aggregating Emissions by Economic Sector

In presenting the Economic Sectors in the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks, the Inventory expands upon the standard IPCC sectors common for UNFCCC reporting. Discussing greenhouse gas emissions relevant to U.S.-specific sectors improves communication of the report’s findings.

In the Electricity Generation economic sector, CO_2 emissions from the combustion of fossil fuels included in the

EIA electric utility fuel consuming sector are apportioned to this economic sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA electric utility sector. Additional sources include CO_2, CH_4, and N_2O from waste incineration, as the majority of municipal solid waste is combusted in "trash-to-steam" electricity generation plants. The Electricity Generation economic sector also includes SF_6 from Electrical Transmission and Distribution, and a portion of CO_2 from Limestone and Dolomite Use (from pollution control equipment installed in electricity generation plants).

In the Transportation economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA transportation fuel consuming sector are apportioned to this economic sector (additional analyses and refinement of the EIA data is further explained in the Energy chapter of this report). Additional emissions are apportioned from the CH_4 and N_2O from Mobile Combustion, based on the EIA transportation sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from transportation refrigeration/air-conditioning systems to this economic sector. Finally, CO_2 emissions from Non-Energy Uses of Fossil Fuels identified as lubricants for transportation vehicles are included in the Transportation economic sector.

For the Industry economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA industrial fuel consuming sector, minus the agricultural use of fuel explained below, are apportioned to this economic sector. Stationary and mobile combustion emissions of CH_4 and N_2O are also based on the EIA industrial sector, minus emissions apportioned to the Agriculture economic sector described below. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with most emissions falling within the Industry economic sector (minus emissions from the other economic sectors). Additionally, all process-related emissions from sources with methods considered within the IPCC Industrial Process guidance have been apportioned to this economic sector. This includes the process-related emissions (i.e., emissions from the actual process to make the material, not from fuels to power the plant) from such activities as Cement Production, Iron and Steel Production and Metallurgical Coke Production, and Ammonia Production. Additionally, fugitive emissions from energy production sources, such as Natural Gas Systems, Coal Mining, and Petroleum Systems are included in the Industry economic sector. A portion of CO_2 from Limestone and Dolomite Use (from pollution control equipment installed in large industrial facilities) are also included in the Industry economic sector. Finally, all remaining CO_2 emissions from Non-Energy Uses of Fossil Fuels are assumed to be industrial in nature (besides the lubricants for transportation vehicles specified above), and are attributed to the Industry economic sector.

As agriculture equipment is included in EIA's industrial fuel consuming sector surveys, additional data is used to extract the fuel used by agricultural equipment, to allow for accurate reporting in the Agriculture economic sector from all sources of emissions, such as motorized farming equipment. Energy consumption estimates are obtained from Department of Agriculture survey data, in combination with separate EIA fuel sales reports. This supplementary data is used to apportion CO_2 emissions from fossil fuel combustion, and CH_4 and N_2O emissions from stationary and mobile combustion (all data is removed from the Industrial economic sector, to avoid double-counting). The other emission sources included in this economic sector are intuitive for the agriculture sectors, such as N_2O emissions from Agricultural Soils, CH_4 from Enteric Fermentation (i.e., exhalation from the digestive tracts of domesticated animals), CH_4 and N_2O from Manure Management, CH_4 from Rice Cultivation, CO_2 emissions from Liming of Agricultural Soils and Urea Application, and CH_4 and N_2O from Forest Fires. N_2O emissions from the Application of Fertilizers to tree plantations (termed "forest land" by the IPCC) are also included in the Agriculture economic sector.

The Residential economic sector includes the CO_2 emissions from the combustion of fossil fuels reported for the EIA residential sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA residential fuel consuming sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from residential air-conditioning systems to this economic sector. N_2O emissions from the Application of Fertilizers to developed land (termed "settlements" by the IPCC) are also included in the Residential economic sector.

The Commercial economic sector includes the CO_2 emissions from the combustion of fossil fuels reported in the EIA commercial fuel consuming sector data. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA commercial sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from commercial refrigeration/air-conditioning systems to this economic sector. Public works sources including direct CH_4 from Landfills and CH_4 and N_2O from Wastewater Treatment and

Composting are included in this economic sector.

[END BOX]

[BEGIN BOX]

Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; or (5) emissions per capita.

Table 2-16 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.4 percent since 1990. This rate is slightly slower than that for total energy consumption and growth in national population since 1990 and much slower than that for electricity consumption and overall gross domestic product, respectively. Total U.S. greenhouse gas emissions are growing at a rate similar to that of fossil fuel consumption since 1990 (see Table 2-16).

Table 2-16: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**	**Growth Rate**[a]
GDP[b]	100	140	157	162	165	165	160	2.5%
Electricity Consumption[c]	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption[c]	100	117	119	117	119	116	108	0.5%
Energy Consumption[c]	100	116	118	118	120	118	112	0.6%
Population[d]	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions[e]	100	115	117	116	117	114	107	0.4%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy-content-weighted values (EIA 2010)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

2.3. *Indirect Greenhouse Gas Emissions (CO, NO_x, NMVOCs, and SO_2)*

The reporting requirements of the UNFCCC[50] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of

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[50] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases. Carbon monoxide is produced when carbon-containing fuels are combusted incompletely. Nitrogen oxides (i.e., NO and NO_2) are created by lightning, fires, fossil fuel combustion, and in the stratosphere from N_2O. Non-CH_4 volatile organic compounds—which include hundreds of organic compounds that participate in atmospheric chemical reactions (i.e., propane, butane, xylene, toluene, ethane, and many others)—are emitted primarily from transportation, industrial processes, and non-industrial consumption of organic solvents. In the United States, SO_2 is primarily emitted from coal combustion for electric power generation and the metals industry. Sulfur-containing compounds emitted into the atmosphere tend to exert a negative radiative forcing (i.e., cooling) and therefore are discussed separately.

One important indirect climate change effect of NMVOCs and NO_x is their role as precursors for tropospheric ozone formation. They can also alter the atmospheric lifetimes of other greenhouse gases. Another example of indirect greenhouse gas formation into greenhouse gases is CO's interaction with the hydroxyl radical—the major atmospheric sink for CH_4 emissions—to form CO_2. Therefore, increased atmospheric concentrations of CO limit the number of hydroxyl molecules (OH) available to destroy CH_4.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[51] which are regulated under the Clean Air Act. Table 2-17 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table 2-17: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,707**	**19,116**	**15,900**	**15,039**	**14,380**	**13,547**	**11,468**
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	**130,038**	**92,243**	**70,809**	**67,238**	**63,625**	**60,039**	**51,452**
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	**20,930**	**15,227**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424

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[51] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2009) and EPA (2010).

Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**14,830**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

[BEGIN BOX]

Box 2-3: Sources and Effects of Sulfur Dioxide

Sulfur dioxide (SO_2) emitted into the atmosphere through natural and anthropogenic processes affects the earth's radiative budget through its photochemical transformation into sulfate aerosols that can (1) scatter radiation from the sun back to space, thereby reducing the radiation reaching the earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., by providing surfaces for heterogeneous chemical reactions). The indirect effect of sulfur-derived aerosols on radiative forcing can be considered in two parts. The first indirect effect is the aerosols' tendency to decrease water droplet size and increase water droplet concentration in the atmosphere. The second indirect effect is the tendency of the reduction in cloud droplet size to affect precipitation by increasing cloud lifetime and thickness. Although still highly uncertain, the radiative forcing estimates from both the first and the second indirect effect are believed to be negative, as is the combined radiative forcing of the two (IPCC 2001). However, because SO_2 is short-lived and unevenly distributed in the atmosphere, its radiative forcing impacts are highly uncertain.

Sulfur dioxide is also a major contributor to the formation of regional haze, which can cause significant increases in acute and chronic respiratory diseases. Once SO_2 is emitted, it is chemically transformed in the atmosphere and returns to the earth as the primary source of acid rain. Because of these harmful effects, the United States has regulated SO_2 emissions in the Clean Air Act.

Electricity generation is the largest anthropogenic source of SO_2 emissions in the United States, accounting for 83 percent in 2009. Coal combustion contributes nearly all of those emissions (approximately 92 percent). Sulfur dioxide emissions have decreased in recent years, primarily as a result of electric power generators switching from high-sulfur to low-sulfur coal and installing flue gas desulfurization equipment.

[END BOX]

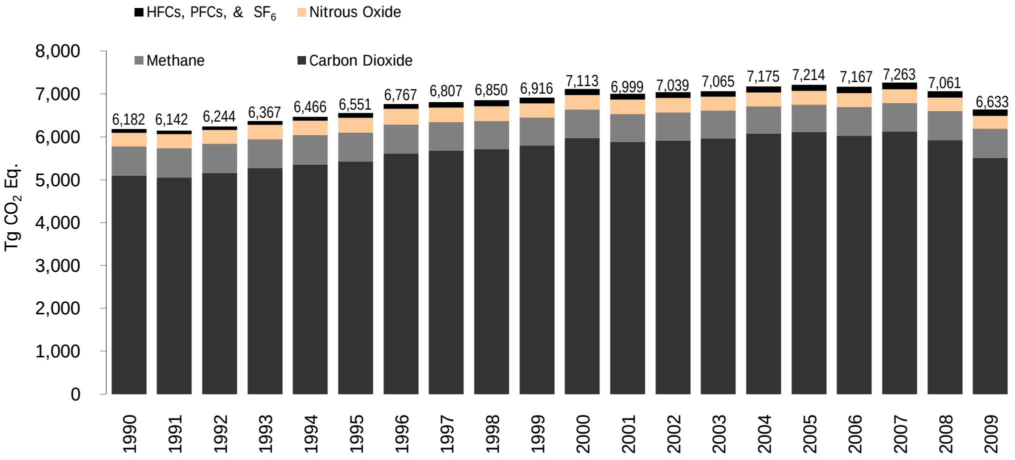


Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

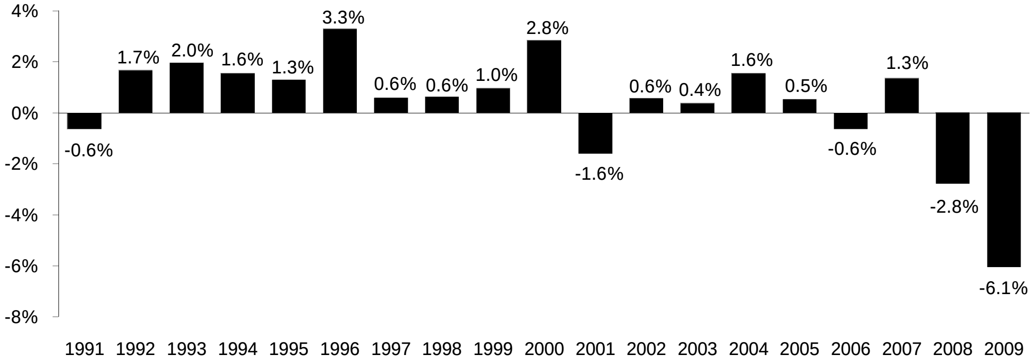


Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

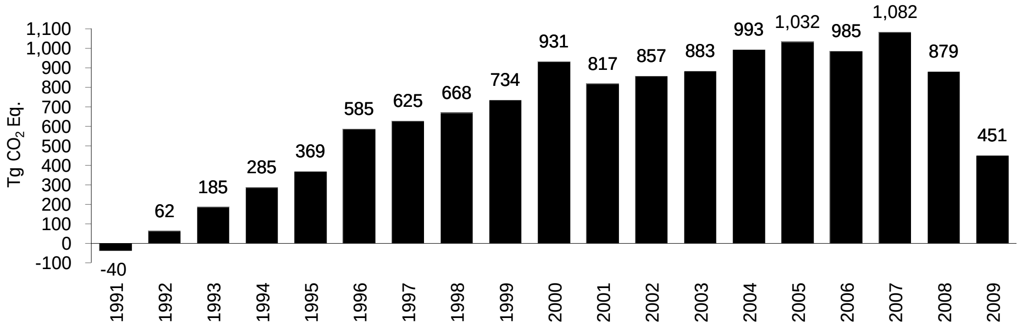
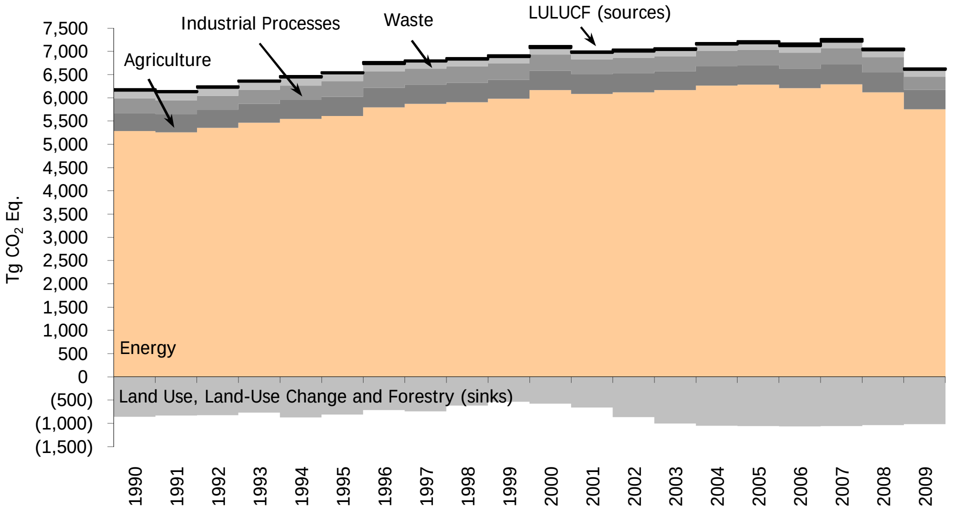


Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sector

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

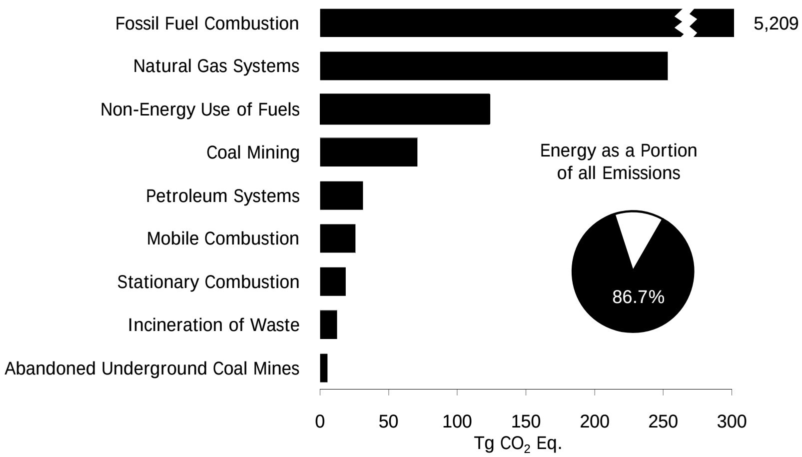
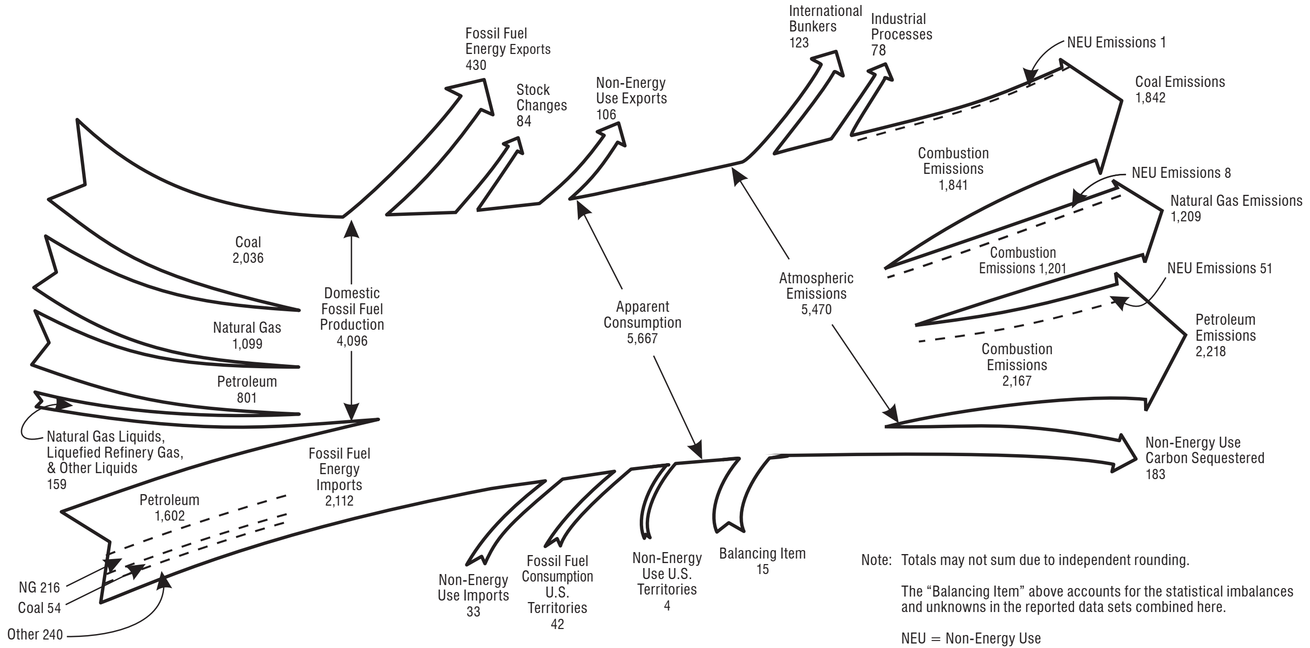


Figure 2-5: 2009 Energy Sector Greenhouse Gas Sources



Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

Figure 2-6 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

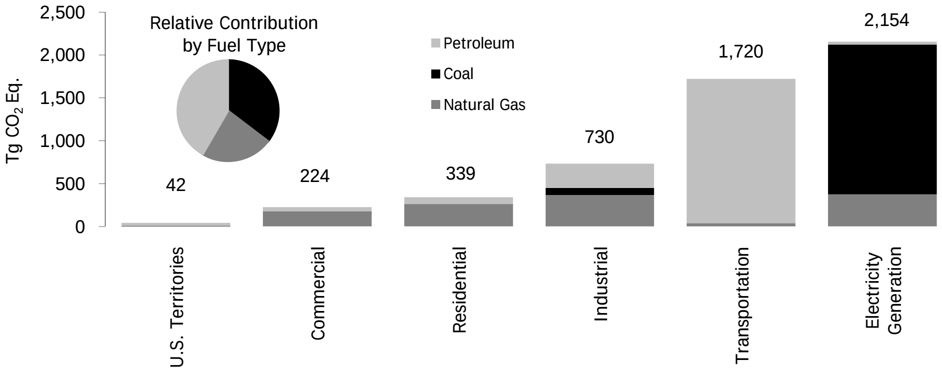


Figure 2-7: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

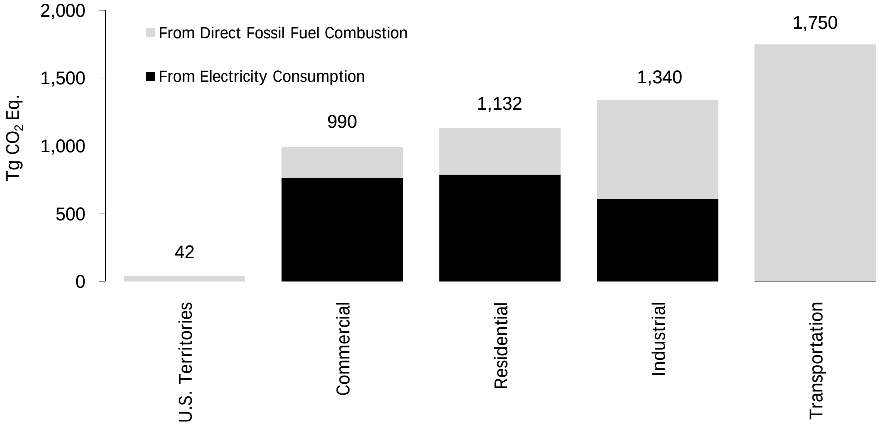


Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

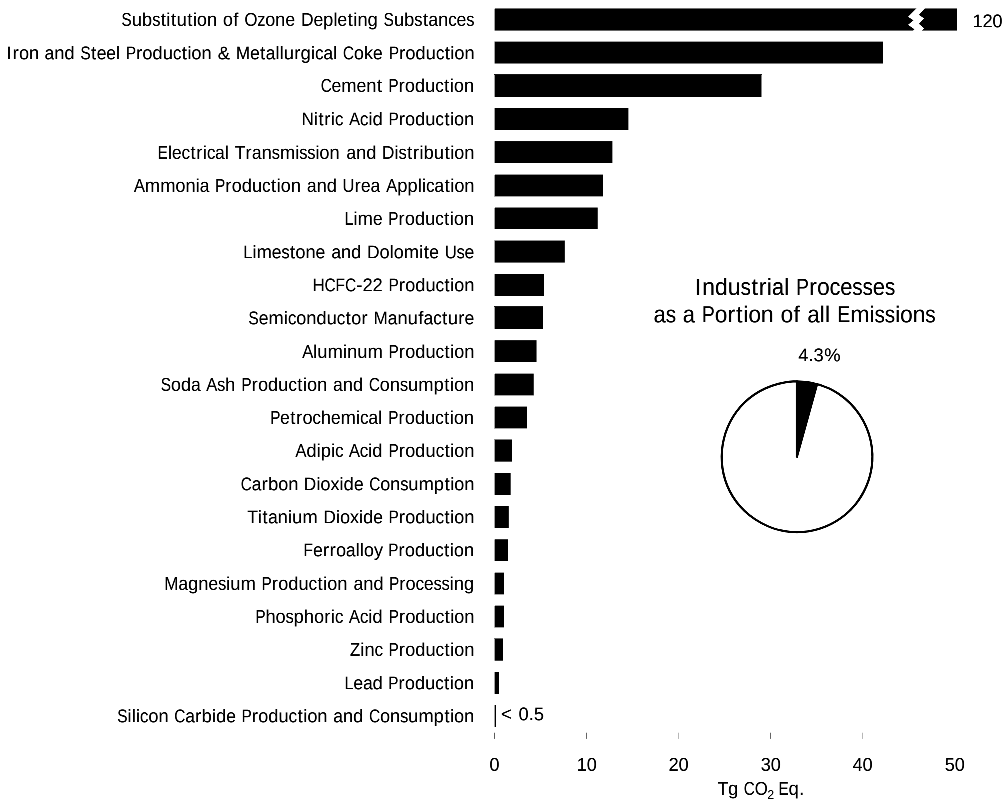


Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

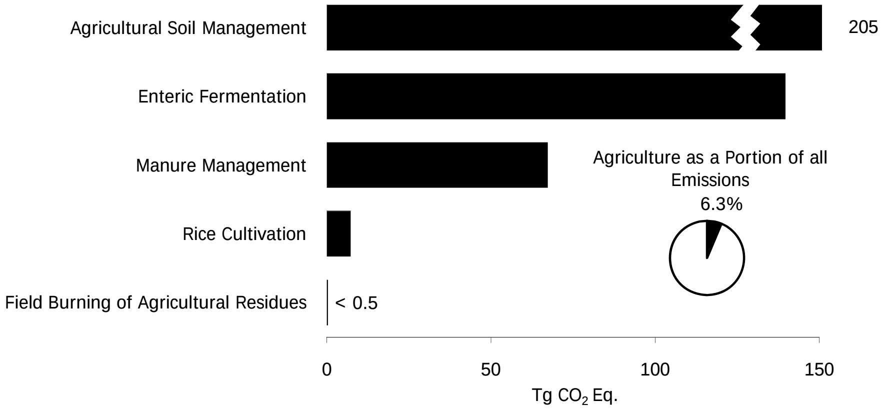


Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

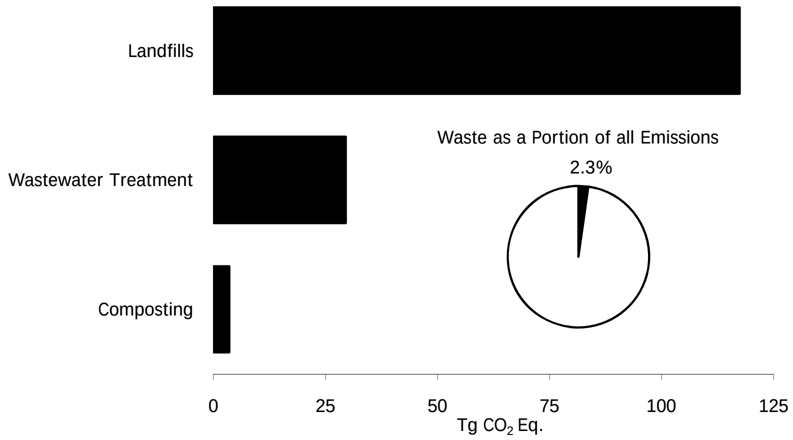


Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

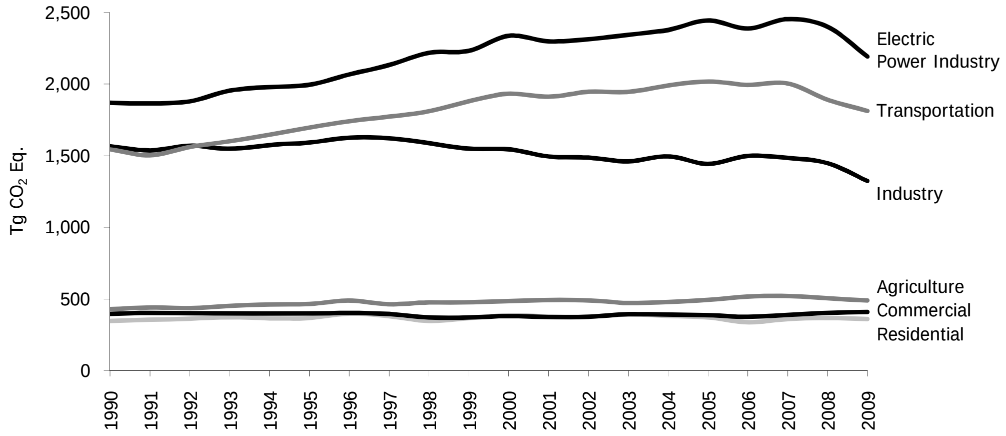


Figure 2-12: Emissions Allocated to Economic Sectors

Note: Does not include U.S. Territories.

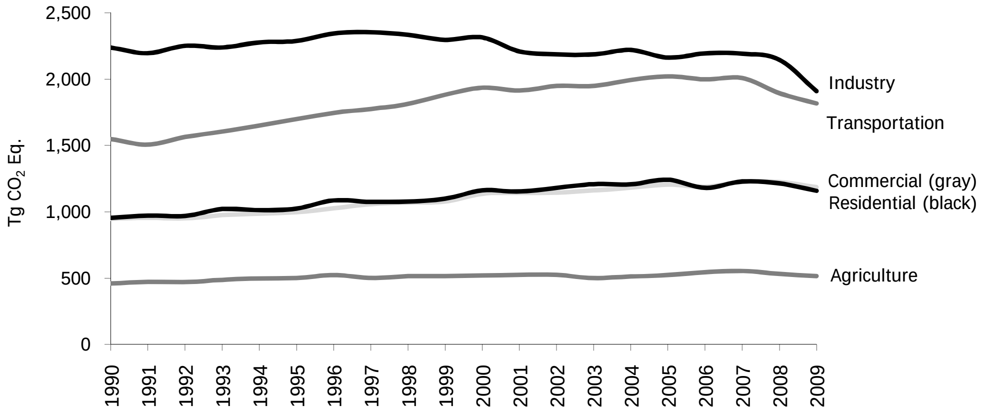


Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

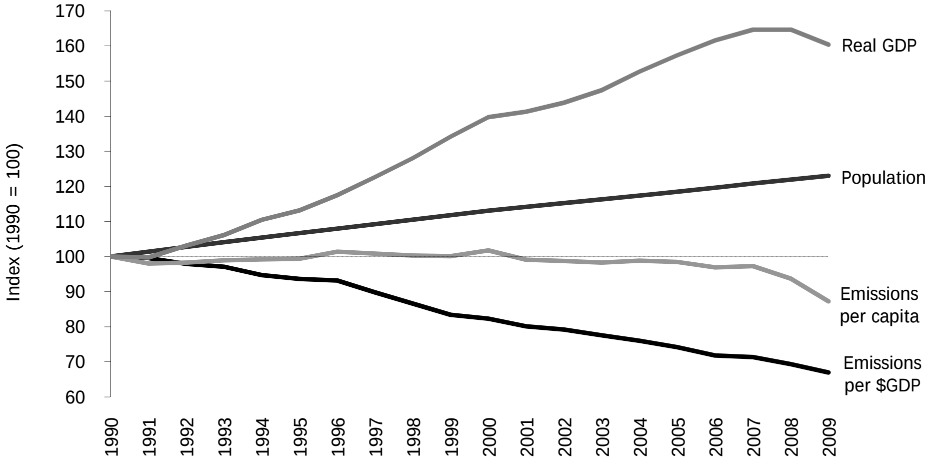


Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86.7 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis[52] in 2009. This included 98, 49, and 13 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (5.6 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 30,398 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[53] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, and mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States.

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,751.1 Tg CO_2 Eq. in 2009, an increase of 9 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood*	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels*	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass – Ethanol*	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2

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[52] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[53] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010).

Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[*]	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
International Bunker Fuels[*]	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903,171**	**5,781,303**	**5,939,434**	**5,842,464**	**5,938,203**	**5,752,327**	**5,377,271**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Petroleum Systems	555	534	490	488	474	453	463
Biomass -Wood[*]	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
International Bunker Fuels[*]	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
Biomass - Ethanol[*]	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**15,590**	**15,171**	**13,872**	**15,202**	**14,634**	**15,408**	**16,037**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[*]	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**185**	**220**	**168**	**156**	**146**	**131**	**120**
Mobile Combustion	142	172	119	108	98	84	77
Stationary Combustion	41	47	47	47	47	46	41
Incineration of Waste	2	1	1	1	1	1	1
International Bunker Fuels[*]	*3*	*3*	*3*	*4*	*4*	*4*	*4*

+ Does not exceed 0.05 Tg CO_2 Eq.

* These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

3.1. Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO_2 from fossil fuel combustion also differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
CH_4	12.1	10.0	9.1	8.5	8.7	8.5	8.1
N_2O	56.8	67.7	51.7	48.1	44.9	40.4	36.7
Total	**4,807.3**	**5,627.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding.

Table 3-4: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Gg)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
CH_4	577	476	431	405	413	407	386
N_2O	183	219	167	155	145	130	118

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2009, CO_2 emissions from fossil fuel combustion decreased by 6.4 percent relative to the previous year. This decrease represents the largest annual decrease in CO_2 emissions from fossil fuel combustion for the twenty-year period.[54] The decrease in CO_2 emissions from fossil fuel combustion was a result of multiple factors including: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price natural gas decreased significantly; and (3) an increase in non-fossil fuel consumption by approximately 2 percent. In 2009, CO_2 emissions from fossil fuel combustion were 5,209.0 Tg CO_2 Eq., or almost 10 percent above emissions in 1990 (see Table 3-5).[55]

Table 3-5: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	2000	2005	2006	2007	2008	2009
Coal	**1,718.4**	**2,065.5**	**2,112.3**	**2,076.5**	**2,106.0**	**2,072.5**	**1,841.0**
Residential	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Commercial	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Industrial	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
U.S. Territories	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	**1,000.6**	**1,217.4**	**1,159.0**	**1,141.3**	**1,218.0**	**1,226.0**	**1,200.9**

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[54] This decrease also represents the largest absolute and percentage decrease since the beginning of EIA's record of annual energy consumption data, beginning in 1949 (EIA 2010a).

[55] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

Residential	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Commercial	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Industrial	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Transportation	36.0	35.6	33.1	33.1	35.3	36.8	36.3
Electricity Generation	175.3	280.8	318.8	338.0	371.3	361.9	373.1
U.S. Territories	NO	0.7	1.3	1.4	1.4	1.6	1.5
Petroleum	**2,019.0**	**2,311.6**	**2,481.5**	**2,434.9**	**2,432.4**	**2,267.1**	**2,166.7**
Residential	97.4	98.8	94.9	83.6	84.6	83.1	81.4
Commercial	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Industrial	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Transportation	1,449.9	1,773.9	1,863.5	1,845.0	1,858.7	1,753.1	1,683.4
Electricity Generation	97.5	88.4	99.2	54.4	53.9	39.2	32.9
U.S. Territories	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Geothermal*	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**

NE (Not estimated)
NO (Not occurring)
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, size of houses, and number of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

CO_2 emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.[56] Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO_2 Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2005 to 2006		2006 to 2007		2007 to 2008		2008 to 2009		Total 2009
Electricity Generation	Coal	-30.1	-1.5%	33.6	1.7%	-27.9	-1.4%	-211.7	-10.8%	1,747.6
Electricity Generation	Natural Gas	19.2	6.0%	33.3	9.9%	-9.3	-2.5%	11.1	3.1%	373.1
Electricity Generation	Petroleum	-44.8	-45.2%	-0.5	-0.9%	-14.7	-27.2%	-6.3	-16.0%	32.9
Transportation [a]	Petroleum	-18.5	-1.0%	13.7	0.7%	-105.6	-5.7%	-69.7	-4.0%	1,683.4
Residential	Natural Gas	-24.9	-9.5%	19.7	8.3%	7.4	2.9%	-7.3	-2.8%	257.2
Commercial	Natural Gas	-9.1	-5.6%	10.2	6.6%	6.2	3.8%	-2.3	-1.3%	167.9
Industrial	Coal	-2.8	-2.4%	-5.6	-5.0%	-4.4	-4.1%	-19.2	-18.7%	83.4
Industrial	Natural Gas	-3.1	-0.8%	11.3	3.0%	2.0	0.5%	-26.0	-6.6%	365.0
All Sectors [b]	**All Fuels [b]**	**-100.1**	**-1.7%**	**103.6**	**1.8%**	**-190.8**	**-3.3%**	**-356.9**	**-6.4%**	**5,209.0**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

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[56] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

In the United States, 83 percent of the energy consumed in 2009 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (9 percent) and by a variety of renewable energy sources[57] (8 percent), primarily hydroelectric power and biofuels (EIA 2010). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 42 percent of total fossil fuel based energy consumption in 2009. Natural gas and coal followed in order of importance, accounting for approximately 32 and 27 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2010).

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[58] These other C containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2009, weather conditions remained constant in the winter and slightly cooler in the summer compared to 2008, as heating degree days decreased slightly and cooling degree days decreased by 3.8 percent. Winter conditions were relatively constant in 2009 compared to 2008, and the winter was slightly warmer than normal, with heating degree days in the United States 0.7 percent below normal (see Figure 3-6). Summer conditions were slightly cooler in 2009 compared to 2008, and summer temperatures were slightly cooler than normal, with cooling degree days 1 percent below normal (see Figure 3-7) (EIA 2010).[59]

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2009)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2009)

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[57] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy

[58] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

[59] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[60]) of existing plants in 2009 remained high at just over 90 percent. Electricity output by hydroelectric power plants increased in 2009 by approximately 6.8 percent. Electricity generated by nuclear plants in 2009 provided nearly 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2010). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2009)

[END BOX]

Fossil Fuel Combustion Emissions by Sector

In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector.

Table 3-7: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (Tg CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Electricity Generation	**1,829.5**	**2,307.5**	**2,413.2**	**2,357.2**	**2,423.8**	**2,371.7**	**2,163.7**
CO_2	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
CH_4	0.6	0.7	0.7	0.7	0.7	0.7	0.7
N_2O	8.1	10.0	10.3	10.1	10.3	10.1	9.0
Transportation	**1,534.6**	**1,866.0**	**1,936.0**	**1,914.1**	**1,926.5**	**1,818.1**	**1,745.5**
CO_2	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
CH_4	4.7	3.4	2.5	2.3	2.2	2.0	2.0
N_2O	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Industrial	**851.2**	**855.9**	**827.5**	**852.8**	**846.5**	**807.0**	**734.1**
CO_2	846.5	851.1	823.1	848.2	842.0	802.9	730.4
CH_4	1.5	1.6	1.4	1.5	1.4	1.3	1.2
N_2O	3.2	3.2	3.0	3.1	3.0	2.8	2.5
Residential	**343.8**	**375.0**	**362.2**	**325.4**	**346.6**	**352.6**	**343.4**
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4
N_2O	1.1	0.9	0.9	0.8	0.9	0.9	0.9
Commercial	**220.2**	**232.1**	**224.8**	**209.7**	**220.6**	**225.4**	**225.2**
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0
CH_4	0.9	0.9	0.9	0.8	0.9	0.9	0.9
N_2O	0.4	0.4	0.4	0.3	0.3	0.3	0.3
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the

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[60] The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2010b).

indirect greenhouse gases NO_x, CO, and NMVOCs.[61] CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. CO emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. CH_4 and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH_4 and N_2O from transportation.[62] Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method of distributing emissions assumes that 564 combustion sources focus on the alternative method as presented in Table 3-8.

Table 3-8: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,537.6**	**1,869.5**	**1,940.8**	**1,918.6**	**1,931.5**	**1,822.8**	**1,750.0**
CO_2	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
CH_4	4.7	3.4	2.5	2.4	2.2	2.0	2.0
N_2O	44.0	53.2	37.0	33.6	30.3	26.2	23.9
Industrial	**1,541.2**	**1,649.3**	**1,567.9**	**1,568.1**	**1,579.7**	**1,525.1**	**1,340.1**
CO_2	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
CH_4	1.8	1.8	1.7	1.7	1.6	1.6	1.4
N_2O	6.3	6.7	6.2	6.2	6.1	5.8	5.0
Residential	**939.7**	**1,140.9**	**1,222.9**	**1,160.1**	**1,206.7**	**1,190.4**	**1,131.6**
CO_2	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
CH_4	4.6	3.6	3.7	3.3	3.6	3.7	3.6
N_2O	3.7	4.2	4.6	4.4	4.5	4.5	4.2
Commercial	**760.8**	**976.8**	**1,032.2**	**1,012.4**	**1,046.0**	**1,036.5**	**990.3**
CO_2	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
CH_4	1.0	1.1	1.1	1.1	1.1	1.2	1.1
N_2O	2.8	3.6	3.8	3.8	3.8	3.8	3.5
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

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[61] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

[62] Separate calculations were performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO_2 from fossil fuel combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO_2 Emissions from Stationary Fossil Fuel Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**
Coal	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
Natural Gas	175.3	280.8	318.8	338.0	371.3	361.9	373.1
Fuel Oil	97.5	88.4	99.2	54.4	53.9	39.2	32.9
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**846.5**	**851.1**	**823.1**	**848.2**	**842.0**	**802.9**	**730.4**
Coal	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Natural Gas	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Fuel Oil	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Commercial	**219.0**	**230.8**	**223.5**	**208.6**	**219.4**	**224.2**	**224.0**
Coal	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Natural Gas	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Fuel Oil	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Residential	**338.3**	**370.7**	**357.9**	**321.5**	**342.4**	**348.2**	**339.2**
Coal	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Natural Gas	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Fuel Oil	97.4	98.8	94.9	83.6	84.6	83.1	81.4
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Coal	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	NO	0.7	1.3	1.4	1.4	1.6	1.5
Fuel Oil	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Total	**3,252.5**	**3,785.3**	**3,856.6**	**3,775.0**	**3,862.8**	**3,776.0**	**3,489.3**

* U.S. Territories are not apportioned by sector, and emissions are from all fuel combustion sources (stationary and mobile) are presented in this table.

Table 3-10: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Electricity Generation	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	0.1	0.1	+	+	+	+
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	**1.5**	**1.6**	**1.4**	**1.5**	**1.4**	**1.3**	**1.2**
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	0.2	0.1	0.2	0.2	0.2	0.2	0.1
Natural Gas	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	0.9	0.9	0.8	0.8	0.7
Commercial	**0.9**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Residential	**4.4**	**3.4**	**3.4**	**3.1**	**3.4**	**3.5**	**3.4**
Coal	0.2	0.1	0.1	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.4	0.5	0.5	0.4	0.5	0.5	0.5
Wood	3.5	2.5	2.6	2.3	2.6	2.7	2.6
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	+	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**7.4**	**6.6**	**6.6**	**6.2**	**6.5**	**6.5**	**6.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Electricity Generation	**8.1**	**10.0**	**10.3**	**10.1**	**10.2**	**10.1**	**9.0**
Coal	7.6	9.4	9.7	9.5	9.7	9.6	8.5
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial	**3.2**	**3.2**	**3.0**	**3.1**	**3.0**	**2.8**	**2.5**
Coal	0.8	0.6	0.6	0.6	0.5	0.5	0.4
Fuel Oil	0.5	0.4	0.5	0.6	0.6	0.5	0.4
Natural Gas	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Wood	1.7	1.9	1.7	1.7	1.7	1.6	1.4
Commercial	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.5	0.5	0.5	0.5	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+

Fuel Oil	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Natural Gas	+		+		+	+	+	+	+
Wood	+		+		+	+	+	+	+
Total	**12.8**		**14.6**		**14.7**	**14.4**	**14.6**	**14.2**	**12.8**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. CH_4 and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.4 percent, respectively.[63] Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2009. CH_4 and N_2O from electricity generation represented 8 and 25 percent of emissions from CH_4 and N_2O emissions from fossil fuel combustion in 2009, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,[64] while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2009 decreased approximately 1.2 percent and 1.0 percent, respectively. The trend in the commercial and residential sectors can largely be attributed to the decreased carbon intensity in the fuels used to generate electricity for these sectors. In addition, electricity consumption in both sectors decreased as a result of the less energy-intensive weather conditions compared to 2008. In 2009, the amount of electricity generated (in kWh) decreased by 4 percent from the previous year. This decline was due to the economic downturn, a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly, and an increase in non-fossil fuel sources used to generate electricity. As a result, CO_2 emissions from the electric power sector decreased by 8.8 percent as the consumption of coal and petroleum for electricity generation decreased by 10.8 percent and 16.6 percent, respectively, in 2009 and the consumption of natural gas for electricity generation, increased by 3.1 percent. The decrease in C intensity of the electricity supply (see Table 3-15) was the result of a decrease in the carbon intensity of fossil fuels consumed to generate electricity and an increase in renewable generation of 5 percent spurred by a 28 percent increase in wind-generated electricity.

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[63] Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-7and Table 3-8, the percentages for CH_4 and N_2O exclude U.S. territory estimates.

[64] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

Industrial Sector

The industrial sector accounted for 14 percent of CO_2 emissions from fossil fuel combustion, 15 percent of CH_4 emissions from fossil fuel combustion, and 7 percent of N_2O emissions from fossil fuel combustion. CO_2, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2010 and EIA 2009c).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[65] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

From 2008 to 2009, total industrial production and manufacturing output decreased by 9.3 and 10.9 percent, respectively (FRB 2010). Over this period, output decreased across all production indices for Food, Petroleum Refineries, Chemicals, Paper, Primary Metals, and Nonmetallic Mineral Products (see Figure 3-10).

Figure 3-10: Industrial Production Indices (Index 2002=100)

Despite the growth in industrial output (41 percent) and the overall U.S. economy (60 percent) from 1990 to 2009, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 13.7 percent over that time. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,340.1 Tg CO_2 Eq., or approximately 12.1 percent below 2008 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 7 and 4 percent of CO_2 emissions from fossil fuel combustion, 42 and 11 percent of CH_4 emissions from fossil fuel combustion, and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,131.6 Tg CO_2 Eq. and 990.3Tg CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from the residential and commercial sectors decreased by 4.9 and 4.5 percent from 2008 to 2009, respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, both sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Emissions from natural gas consumption represent about 76 and 75 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. In 2009, natural gas CO_2 emissions from the residential and commercial sectors decreased by 2.8 percent and 1.3 percent, respectively. The decrease in natural gas emissions in both sectors is a result of less energy-intensive weather conditions in the United States compared to

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[65] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

2008.

U.S. Territories

Emissions from U.S. territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described the Methodology section for CO_2 from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

The transportation end-use sector accounted for 1,745.5 Tg CO_2 Eq. in 2009, which represented 33 percent of CO_2 emissions, 24 percent of CH_4 emissions, and 65 percent of N_2O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 123.1 Tg CO_2 in 2009; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 64 percent of CO_2 emissions, medium- and heavy-duty trucks 20 percent, commercial aircraft 6 percent, and other sources 9 percent. Light-duty truck CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation, CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO_2 emissions by mode and fuel type.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (235.1 Tg) between 1990 and 2009, an annualized increase of 0.8 percent. The 4 percent decline in emissions between 2008 and 2009 followed the previous year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil.[66] Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 in the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,111.7 Tg in 2009, an increase of 17 percent (161.3 Tg) from 1990. CO_2 emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 6 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 52 percent and declined to 40 percent in 2009.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2008

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2008

Light-duty truck[67] CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation[68], CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

Table 3-12: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Gasoline	**983.7**	**1,135.0**	**1,187.8**	**1,178.2**	**1,181.2**	**1,130.3**	**1,125.7**
Passenger Cars	621.4	640.6	658.0	635.0	628.7	594.0	593.3
Light-Duty Trucks	309.1	446.4	478.7	491.5	500.1	486.5	485.9
Medium- and Heavy-Duty Trucks[b]	38.7	36.0	34.9	35.5	36.1	33.7	30.6
Buses	0.3	0.4	0.4	0.4	0.4	0.4	0.3
Motorcycles	1.7	1.8	1.6	1.9	2.1	2.1	2.1
Recreational Boats	12.4	9.8	14.1	14.0	13.9	13.5	13.4
Distillate Fuel Oil (Diesel)	**262.9**	**402.5**	**451.8**	**470.3**	**476.3**	**443.5**	**402.5**
Passenger Cars	7.9	3.7	4.2	4.1	4.1	3.9	3.9
Light-Duty Trucks	11.5	20.1	25.8	26.8	27.3	26.9	26.7
Medium- and Heavy-Duty	190.5	309.6	360.6	370.1	376.1	356.0	321.8

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[66] Biofuel estimates are presented for informational purposes only in the Energy chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards" web page: http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm

[67] Includes "light-duty trucks" fueled by gasoline, diesel and LPG.

[68] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Trucks[b]							
Buses	8.0	10.2	10.6	10.8	10.8	10.3	9.3
Rail	35.5	42.1	45.6	47.8	46.6	43.2	36.2
Recreational Boats	2.0	2.7	3.1	3.2	3.3	0.9	3.5
Ships and Other Boats	7.5	14.1	8.1	7.5	8.2	2.2	1.2
International Bunker Fuels [c]	*11.7*	*6.3*	*9.4*	*8.8*	*8.2*	*9.0*	*8.3*
Jet Fuel	**176.2**	**199.8**	**194.2**	**169.5**	**168.7**	**155.1**	**138.8**
Commercial Aircraft	135.4	169.2	161.2	137.1	138.1	122.2	111.4
Military Aircraft	34.4	21.1	18.1	16.4	16.1	16.3	14.1
General Aviation Aircraft	6.4	9.5	14.9	16.0	14.5	16.6	13.3
International Bunker Fuels [c]	*46.4*	*58.8*	*56.7*	*74.6*	*73.8*	*75.5*	*69.4*
Aviation Gasoline	**3.1**	**2.5**	**2.4**	**2.3**	**2.2**	**2.0**	**1.8**
General Aviation Aircraft	3.1	2.5	2.4	2.3	2.2	2.0	1.8
Residual Fuel Oil	**22.6**	**33.3**	**19.3**	**23.0**	**29.0**	**19.9**	**12.0**
Ships and Other Boats[d]	22.6	33.3	19.3	23.0	29.0	19.9	12.0
International Bunker Fuels [c]	*53.7*	*33.3*	*43.6*	*45.0*	*45.6*	*49.2*	*45.4*
Natural Gas	**36.0**	**35.6**	**33.1**	**33.1**	**35.3**	**36.8**	**36.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.4	0.8	0.8	1.0	1.1	1.1
Pipeline	36.0	35.2	32.2	32.3	34.3	35.7	35.2
LPG	**1.4**	**0.7**	**1.7**	**1.7**	**1.4**	**2.4**	**2.5**
Light-Duty Trucks	0.6	0.5	1.3	1.2	1.0	1.8	1.8
Medium- and Heavy-Duty Trucks[b]	0.8	0.3	0.4	0.5	0.4	0.7	0.7
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**3.4**	**4.7**	**4.5**	**5.0**	**4.7**	**4.4**
Rail	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Total	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Total (Including Bunkers) [c]	**1,600.8**	**1,911.4**	**2,011.1**	**2,011.0**	**2,026.6**	**1,928.3**	**1,847.2**

[a] This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.

[b] Includes medium- and heavy-duty trucks over 8,500 lbs.

[c] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

Note: Totals may not sum due to independent rounding.

Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

+ Less than 0.05 Tg CO_2 Eq.

- Unreported or zero

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.[69]

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[69] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2009.

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the second largest source of U.S. N_2O emissions (9 percent). From 1990 to 2009, mobile source CH_4 emissions declined by 58 percent, to 2.0 Tg CO_2 Eq. (93 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 46 percent, to 23.9 Tg CO_2 Eq. (77 Gg). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 50 percent decrease in mobile source N_2O emissions from 1998 to 2009 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

Table 3-13: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Gasoline On-Road	**4.2**	**2.8**	**1.9**	**1.7**	**1.6**	**1.4**	**1.3**
Passenger Cars	2.6	1.6	1.1	1.0	0.9	0.8	0.7
Light-Duty Trucks	1.4	1.1	0.7	0.6	0.6	0.6	0.6
Medium- and Heavy-Duty Trucks and Buses	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road	**0.4**	**0.5**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**
Ships and Boats	+	+	+	+	+	+	+
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Agricultural Equipment[b]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[c]	+	0.1	0.1	0.1	0.1	0.1	0.1
Other[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**3.4**	**2.5**	**2.3**	**2.2**	**2.0**	**2.0**

[a] See Annex 3.2 for definitions of on-road vehicle types.

[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO_2 Eq.

Table 3-14: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Gasoline On-Road	**40.1**	**48.4**	**32.1**	**29.0**	**25.5**	**21.8**	**19.9**
Passenger Cars	25.4	25.2	17.7	15.7	13.7	11.7	10.0
Light-Duty Trucks	14.1	22.4	13.6	12.5	11.1	9.5	9.3
Medium- and Heavy-Duty Trucks and Buses	0.6	0.9	0.8	0.7	0.7	0.6	0.5
Motorcycles	+	+	+	+	+	+	+

Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel On-Road	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.6**	**4.3**	**4.3**	**4.2**	**4.3**	**3.8**	**3.6**
Ships and Boats	0.6	0.9	0.6	0.7	0.8	0.5	0.4
Rail	0.3	0.3	0.4	0.4	0.4	0.3	0.3
Aircraft	1.7	1.9	1.9	1.6	1.6	1.5	1.3
Agricultural Equipment[b]	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment[c]	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Other[d]	0.4	0.5	0.6	0.6	0.6	0.6	0.6
Total	**43.9**	**53.2**	**36.9**	**33.6**	**30.3**	**26.1**	**23.9**

[a] See Annex 3.2 for definitions of on-road vehicle types.

[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO_2 Eq.

CO_2 from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2011). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).[70]

   For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every 4 years). These consumption data sets help inform the annual surveys to arrive at the

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[70] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 42 Tg CO_2 Eq. in 2009.

national total and sectoral breakdowns for that total. [71]

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[72]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2010), Coffeyville (2010), U.S. Census Bureau (2010), EIA (2010c), USGS (1991 through 2010), USGS (1994 through 2010), USGS (1995, 1998, 2000 through 2002, 2007, and 2009), USGS (1991 through 2009a), and USGS (1991 through 2009b).[73]
3. *Adjust for conversion of fuels and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[74] Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[75] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2011) and data for synthetic natural gas were collected from EIA (2009b), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), and EIA (2007b).
4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on the Federal Highway Administration's (FHWA) VMT that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2010), Benson (2002 through 2004), DOE (1993 through 2010), EIA (2009a), EIA (1991 through 2010), EPA (2009), and FHWA (1996 through 2010).[76]

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[71] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[72] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

[73] See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes chapter.

[74] Energy statistics from EIA(2010c) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

[75] These adjustments are explained in greater detail in Annex 2.1.

[76] FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.

Fuel use by vehicle class (also in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2011).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[77] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006 and 2009); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2010) for 1990 through 2001, 2007 and 2008, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.

7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's Emissions of Greenhouse Gases in the United States 2008 (EIA 2009a), and an EPA analysis of C content coefficients used in the mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.

8. *Estimate CO_2 Emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector.

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2010); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2010). Fuel use by vehicle class (found in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009.

    - For non-road vehicles, activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), BEA (1991 through 2009), Benson (2002 through 2004), DOE (1993 through 2010),

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was estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[77] See International Bunker Fuels section in this chapter for a more detailed discussion.

DESC (2011), DOC (1991 through 2010), DOT (1991 through 2010), EIA (2009a), EIA (2009d), EIA (2007a), EIA (2002), EIA (1991 through 2011), EPA (2010b), FAA (2008), and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2011). [78] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2010) and USAF (1998). [79]

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[80] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990	2000	2005	2006	2007	2008	2009
Residential [a]	57.4	56.6	56.6	56.5	56.3	56.1	56.0
Commercial [a]	59.2	57.2	57.5	57.2	57.1	56.8	56.9
Industrial [a]	64.3	62.8	64.3	64.5	64.0	63.6	63.2
Transportation [a]	71.1	71.3	71.4	71.6	71.9	71.6	71.5

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[78] Data for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model. That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year. Data for inventory years 2006-2009 were developed using AEDT. The AEDT model dynamically models aircraft performance in space and time to produce fuel burn, emissions and noise. Full flight gate-to-gate analyses are possible for study sizes ranging from a single flight at an airport to scenarios at the regional, national, and global levels. AEDT is currently used by the U.S. government to consider the interdependencies between aircraft-related fuel burn, noise and emissions.

[79] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

[80] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

Electricity Generation [b]	87.3		86.2		85.8	85.4	84.7	84.9	83.7
U.S. Territories [c]	73.0		72.5		73.4	73.5	73.8	73.3	73.1
All Sectors [c]	**73.0**		**73.0**		**73.5**	**73.5**	**73.3**	**73.1**	**72.4**

[a] Does not include electricity or renewable energy consumption.

[b] Does not include electricity produced using nuclear or renewable energy.

[c] Does not include nuclear or renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption.

Over the twenty-year period of 1990 through 2009, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2009 was approximately 9 percent below levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2010).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

C intensity estimates were developed using nuclear and renewable energy data from EIA (2010), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

Uncertainty and Time Series Consistency

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2009. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The

United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[81] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[82]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[83] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2009 were estimated to be between 5,149.0 and 5,522.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 1 percent below to 6 percent above the 2009 emission estimate of 5,209.0.0 Tg CO_2 Eq.

Table 3-16: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Coal [b]	**1,841.0**	**1,779.3**	**2,015.6**	**-3%**	**+9%**
Residential	0.6	0.6	0.7	-6%	+15%
Commercial	5.8	5.5	6.7	-5%	+15%
Industrial	83.4	80.5	97.5	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,747.6	1,680.4	1,915.8	-4%	+10%
U.S. Territories	3.5	3.1	4.2	-12%	+19%

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[81] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[82] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[83] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Natural Gas [b]	**1,200.9**	**1,209.4**	**1,276.6**	**+1%**	**+6%**
Residential	257.2	250.0	275.2	-3%	+7%
Commercial	167.9	163.2	179.7	-3%	+7%
Industrial	365.0	374.9	412.7	+3%	+13%
Transportation	36.3	35.2	38.8	-3%	+7%
Electricity Generation	373.1	362.3	392.0	-3%	+5%
U.S. Territories	1.5	1.3	1.7	-12%	+17%
Petroleum [b]	**2,166.7**	**2,067.2**	**2,323.5**	**-5%**	**+7%**
Residential	81.4	76.9	85.7	-6%	+5%
Commercial	50.3	47.9	52.4	-5%	+4%
Industrial	282.0	231.2	330.4	-18%	+17%
Transportation	1,683.4	1,598.6	1,826.8	-5%	+9%
Electric Utilities	32.9	31.5	35.4	-4%	+7%
U.S. Territories	36.7	33.8	40.9	-8%	+11%
Total (excluding Geothermal) [b]	**5,208.6**	**5,148.76**	**5,522.0**	**-1%**	**+6%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,209.0**	**5,149.0**	**5,522.4**	**-1%**	**+6%**

NA (Not Applicable)
NE (Not Estimated)

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.

[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2011) updated energy consumption statistics across the time series. These revisions primarily impacted the emission estimates for 2007 and 2008. In addition, the coal emissions for U.S. Territories decreased from 2001 to 2008 due to the closure of a coal power plant in the U.S. Virgin Islands. Overall, these changes resulted in an average annual increase of 0.5 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2008.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to

EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Stationary Combustion

Methodology

CH_4 and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2010). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).[84] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[85] Construction and agricultural fuel use was obtained from EPA (2010a). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA.

Emission factors for the four end-use sectors were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty and Time-Series Consistency

CH_4 emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[86] For these variables, the uncertainty

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[84] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[85] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

[86] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[87] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2009 (including biomass) were estimated to be between 4.1 and 14.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 127 percent above the 2009 emission estimate of 6.2 Tg CO_2 Eq.[88] Stationary combustion N_2O emissions in 2009 (*including* biomass) were estimated to be between 9.8 and 36.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 187 percent above the 2009 emissions estimate of 12.8 Tg CO_2 Eq.

Table 3-17: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Stationary Combustion	CH_4	6.2	4.1	14.0	-34%	+127%
Stationary Combustion	N_2O	12.8	9.8	36.7	-23%	+187%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to a couple of changes, mainly impacting 2007 and 2008 estimates. Slight changes to emission estimates for sectors are due to revised data from EIA (2010). Wood consumption data in EIA (2011) were revised for the residential, commercial, and industrial sectors for 2007 and 2008 as well as for the electric power sector for 2006 through 2008. The combination of the methodological and historical data changes resulted in an average annual increase of 0.01 Tg CO_2 Eq. (0.2 percent) in CH_4 emissions from stationary combustion and an average annual decrease of 0.08 Tg CO_2 Eq. (0.5 percent) in N_2O emissions from stationary combustion for the period 1990 through 2008.

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[87] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[88] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH_4 and N_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs)[89] are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[90]

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from

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[89] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

[90] Additional information regarding the model can be found online at http://www.epa.gov/OMS/m6.htm.

AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2010 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2010).[91] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2010) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2010). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2010a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[92] Activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DOE (1993 through 2010), DESC (2011), DOT (1991 through 2010), EIA (2008a, 2007a, 2007b, 2002), EIA (2007 through 2010), EIA (1991 through 2011), EPA (2009), Esser (2003 through 2004), FAA (2011, 2010, and 2006), Gaffney (2007), and (2006 through 2010). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2009 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Mobile combustion CH_4 emissions from all mobile sources in 2009 were estimated to be between 1.8 and 2.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 15 percent above the corresponding 2009 emission estimate of 2.0 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2009 were estimated to be between 20.5 and 27.9 Tg CO_2 Eq., indicating a range of 14 percent below to 17 percent above the corresponding 2009 emission estimate of 23.9 Tg CO_2 Eq.

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[91] Fuel use by vehicle class (VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline were estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

[92] The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

Table 3-18: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate[a] (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mobile Sources	CH_4	2.0	1.8	2.2	-9%	+15%
Mobile Sources	N_2O	23.9	20.5	27.9	-14%	+17%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH_4 and N_2O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA/QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. Each year, a number of adjustments are made to the methodologies used in calculating emissions in the current Inventory relative to previous Inventory reports. One of the revisions that were made this year was incorporating motor vehicle age distribution from EPA's MOtor Vehicle Emission Simulator (MOVES) model. MOVES is EPA's tool for estimating emissions from highway vehicles, based on analysis of millions of emission test results and considerable advances in EPA's understanding of vehicle emissions. Population data from the MOVES model was used to estimate the age distribution of motor vehicles in the United States.

Planned Improvements

While the data used for this report represent the most accurate information available, four areas have been identified that could potentially be improved in the short-term given available resources.

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO_2 emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N_2O and CH_4 emissions factors for non-road equipment.
3. Examine the feasibility of estimating aircraft N_2O and CH_4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N_2O and CH_4

emissions are more dependent on aircraft takeoffs and landings than on total aircraft fuel consumption; however, aircraft emissions are currently estimated from fuel consumption data. FAA's SAGE and AEDT databases contain detailed data on takeoffs and landings for each calendar year starting in 2000, and could potentially be used to conduct a Tier II analysis of aircraft emissions. This methodology will require a detailed analysis of the number of takeoffs and landings by aircraft type on domestic trips, the development of procedures to develop comparable estimates for years prior to 2000, and the dynamic interaction of ambient air with aircraft exhausts is developed. The feasibility of this approach will be explored.

Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates will be investigated. Continue to examine the use of EPA's MOVES model in the development of the inventory estimates, including use for uncertainty analysis. Although the inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. As MOVES goes through additional testing and refinement, the use of MOVES will be further explored.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2009 from the non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2009, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,451.0 TBtu, an increase of 0.2 percent since 1990 (see Table 3-20). About 49.9 Tg of the C (182.8 Tg CO_2 Eq.) in these fuels was stored, while the remaining 33.6 Tg C (123.4 Tg CO_2 Eq.) was emitted.

Table 3-19: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Potential Emissions	310.8	383.6	381.6	381.7	370.1	344.9	306.1
C Stored	192.2	238.6	238.3	236.1	232.8	204.0	182.8
Emissions as a % of Potential	38%	38%	38%	38%	37%	41%	40%
Emissions	**118.6**	**144.9**	**143.4**	**145.6**	**137.2**	**141.0**	**123.4**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2011) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[93] Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC/UNEP/OECD/IEA (1997), which in turn draws from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2000	2005	2006	2007	2008	2009
Industry	**4,181.1**	**5,214.4**	**5,174.4**	**5,163.2**	**5,060.7**	**4,671.9**	**4,267.7**
Industrial Coking Coal	+	53.0	79.8	62.3	1.7	28.4	6.1
Industrial Other Coal	8.2	12.4	11.9	12.4	12.4	12.4	12.4
Natural Gas to Chemical Plants	277.3	420.3	397.0	407.7	412.5	395.2	366.0
Asphalt & Road Oil	1,170.2	1,275.7	1,323.2	1,261.2	1,197.0	1,012.0	873.1
LPG	1,119.2	1,607.0	1,444.0	1,488.6	1,483.0	1,409.6	1,446.2
Lubricants	186.3	189.9	160.2	156.1	161.2	149.6	134.5
Pentanes Plus	77.5	229.3	146.3	105.5	132.7	114.9	93.4
Naphtha (<401 ° F)	325.9	593.7	679.6	618.1	542.6	467.3	450.7
Other Oil (>401 ° F)	661.4	527.0	514.8	573.4	669.2	599.2	392.5
Still Gas	21.3	12.6	67.7	57.2	44.2	47.3	133.9
Petroleum Coke	54.8	35.3	128.8	172.2	155.9	174.4	133.0
Special Naphtha	100.8	94.4	60.9	68.9	75.5	83.2	44.2
Distillate Fuel Oil	7.0	11.7	16.0	17.5	17.5	17.5	17.5
Waxes	33.3	33.1	31.4	26.1	21.9	19.1	12.2
Miscellaneous Products	137.8	119.2	112.8	136.0	133.5	142.0	151.8
Transportation	**176.0**	**179.4**	**151.3**	**147.4**	**152.2**	**141.3**	**127.1**
Lubricants	176.0	179.4	151.3	147.4	152.2	141.3	127.1
U.S. Territories	**86.7**	**152.2**	**121.9**	**133.4**	**108.4**	**126.7**	**56.3**
Lubricants	0.7	3.1	4.6	6.2	5.9	2.7	1.0

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[93] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

Other Petroleum (Misc. Prod.)	86.0		149.1		117.3	127.2	102.5	124.1	55.2
Total	**4,443.8**		**5,546.0**		**5,447.6**	**5,444.0**	**5,321.3**	**4,940.0**	**4,451.0**

+ Does not exceed 0.05 TBtu

Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.

Note: Totals may not sum due to independent rounding.

Table 3-21: 2009 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2 Eq.)
Industry	**4,267.7**	-	**79.8**	-	**49.5**	**30.3**	**111.1**
Industrial Coking Coal	6.1	31.00	0.2	0.10	0.0	0.2	0.6
Industrial Other Coal	12.4	25.82	0.3	0.58	0.2	0.1	0.5
Natural Gas to Chemical Plants	366.0	14.47	5.3	0.58	3.1	2.2	8.1
Asphalt & Road Oil	873.1	20.55	17.9	1.00	17.9	0.1	0.3
LPG	1,446.2	17.06	24.7	0.58	14.3	10.3	37.9
Lubricants	134.5	20.20	2.7	0.09	0.2	2.5	9.0
Pentanes Plus	93.4	19.10	1.8	0.58	1.0	0.7	2.7
Naphtha (<401° F)	450.7	18.55	8.4	0.58	4.9	3.5	12.9
Other Oil (>401° F)	392.5	20.17	7.9	0.58	4.6	3.3	12.2
Still Gas	133.9	17.51	2.3	0.58	1.4	1.0	3.6
Petroleum Coke	133.0	27.85	3.7	0.30	1.1	2.6	9.5
Special Naphtha	44.2	19.74	0.9	0.58	0.5	0.4	1.3
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	12.2	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	151.8	20.31	3.1	0.00	0.0	3.1	11.3
Transportation	**127.1**	-	**2.6**	-	**0.2**	**2.3**	**8.5**
Lubricants	127.1	20.20	2.6	0.09	0.2	2.3	8.5
U.S. Territories	**56.3**	-	**1.1**	-	**0.1**	**1.0**	**3.7**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	**4,451.0**	**-**	**83.5**	**-**	**49.9**	**33.6**	**123.4**

+ Does not exceed 0.05 Tg

- Not applicable.

[a] To avoid double counting, net exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2010), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2007a), and pesticide sales and use estimates

(EPA 1998, 1999, 2002, 2004); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2009); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2011); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2009a,b); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2010); and the American Chemistry Council (ACC 2003-2010). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-22 and Table 3-23), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2009 was estimated to be between 97.6 and 135.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 10 percent above the 2009 emission estimate of 123.4 Tg CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Feedstocks	CO_2	79.3	63.4	96.1	-20%	21%
Asphalt	CO_2	0.3	0.1	0.6	-58%	119%
Lubricants	CO_2	17.7	14.6	20.5	-17%	16%
Waxes	CO_2	0.4	0.3	0.7	-29%	74%
Other	CO_2	25.7	10.3	27.0	-60%	5%
Total	**CO_2**	123.4	97.6	135.3	-21%	10%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

Table 3-23: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2009 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a]			
			(%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	58%	56%	60%	-3%	4%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO_2	9%	4%	17%	-57%	91%
Waxes	CO_2	58%	49%	71%	-15%	22%
Other	CO_2	17%	16%	66%	-3%	292%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-23, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2009 as well as their trends across the time series.

Recalculations Discussion

In previous Inventories, the storage factor for asphalt was incorrectly assumed to be 100 percent. For the current Inventory, it has been updated to 99.6 percent to reflect some loss of VOCs (see Annex 2.3 for more detailed discussion).

Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 were released in the past year. MECS data are only released once every four years and contribute to approximately 28 percent (as a time-weighted average) of the C accounted for in feedstocks. MECS data are used to estimate the amount of C emitted from energy recovery. Updating the energy recovery emission estimates with this new data affected emissions from 2003 through 2009, resulting in annual average increases of 7 percent from 2003 through 2009. In addition, the entire energy recovery time series was recalculated to adjust for energy recovered from combustion of scrap tires. Carbon emissions from scrap tires were inadvertently included in the energy recovery estimates; however, they are already accounted for in the Incineration of Waste category.[94] MECS data were adjusted to remove C from scrap tires used as fuel in cement kilns, lime kilns, and electric arc furnaces. This adjustment resulted in decreases in emissions across the entire time series. Emissions decreased by 0.3, 2.1, 1.3, and 1.5 percent for MECS-reporting years 1991, 1994, 1998, and 2002, respectively. Updating the energy recovery emission estimates with the 2006 MECS data combined with adjusting for combustion of scrap tires increased the 2006 emission estimate by 9.5 percent. Overall, emissions from energy recovery averaged over the entire time series increased by 1.2 percent when compared to last year's inventory estimate because the increase resulting from updating the MECS data more than offsets the decrease from adjusting for scrap tire combustion across the time series.

Planned Improvements

There are several improvements planned for the future:

- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). EPA plans to better understand these trends to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- More accurate accounting of C in petrochemical feedstocks. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. EPA plans to research this discrepancy by assessing the trends on both sides of the C balance. An initial review of EIA (2011) data indicates that trends in LPG consumption for non-energy uses may largely contribute to this discrepancy.
- More accurate accounting of C in imports and exports. As part of its effort to address the C balance discrepancy, EPA will examine its import/export adjustment methodology to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for.
- EPA recently researched updating the average carbon content of solvents, since the entire time series depends on one year's worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive carbon in solvents. EPA plans to identify additional sources of solvents data in order to update the C content assumptions.

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.

3.3. *Incineration of Waste (IPCC Source Category 1A1a)*

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000, Goldstein

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[94] From a regulatory-definition perspective combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is not considered "incineration;" however the use of the term "incineration" in this document also applies to the combustion of scrap tires and other materials for energy recovery.

and Matdes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. As noted above, tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the carbon mass balance for non-energy uses of fossil fuels.

Approximately 26 million metric tons of MSW was incinerated in the United States in 2009 (EPA 2011). CO_2 emissions from incineration of waste rose 54 percent since 1990, to an estimated 12.3 Tg CO_2 Eq. (12,300 Gg) in 2009, as the volume of tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of N_2O and CH_4 emissions (De Soete 1993; IPCC 2006). N_2O emissions from the incineration of waste were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2009, and have not changed significantly since 1990. CH_4 emissions from the incineration of waste were estimated to be less than 0.05 Tg CO_2 Eq. (less than 0.5 Gg CH_4) in 2009, and have not changed significantly since 1990.

Table 3-24: CO_2 and N_2O Emissions from the Incineration of Waste (Tg CO_2 Eq.)

Gas/Waste Product	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8.0**	**11.1**	**12.5**	**12.5**	**12.7**	**12.2**	**12.3**
Plastics	5.6	6.1	6.9	6.7	6.7	6.1	6.2
Synthetic Rubber in Tires	0.3	1.5	1.6	1.7	1.8	1.8	1.8
Carbon Black in Tires	0.4	1.8	2.0	2.1	2.3	2.3	2.3
Synthetic Rubber in MSW	0.9	0.7	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.0	1.2	1.2	1.2	1.2	1.2
N_2O	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
CH_4	+	+	+	+	+	+	+
Total	**8.5**	**11.5**	**12.9**	**12.9**	**13.1**	**12.5**	**12.7**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-25: CO_2 and N_2O Emissions from the Incineration of Waste (Gg)

Gas/Waste Product	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**7,989**	**11,112**	**12,450**	**12,531**	**12,700**	**12,169**	**12,300**
Plastics	5,588	6,104	6,919	6,722	6,660	6,148	6,233
Synthetic Rubber in Tires	308	1,454	1,599	1,712	1,823	1,823	1,823
Carbon Black in Tires	385	1,818	1,958	2,113	2,268	2,268	2,268
Synthetic Rubber in MSW	872	689	781	775	791	770	782
Synthetic Fibers	838	1,046	1,194	1,208	1,159	1,161	1,195
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in tires. These emissions were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 1999 through 2003, 2005 through 2011) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2009 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Markets in the United States, 2007 Edition (RMA 2009a). For 2008 and 2009, synthetic rubber mass in tires is assumed to be equal to that in 2007 due to a lack of more recently available data.

Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: carbon content for 1990 through 1998 is based on the 1998 value; content for 1999 through 2001 is the average of 1998 and 2002 values; and content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2009b).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO_2 emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N_2O and CH_4 emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data on total waste incinerated was not available for 2009, so this value was assumed to equal the most recent value available (2008). Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted.

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0
2000	252,328,354	25,974,978	10.3
2005	259,559,787	25,973,520	10.0
2006	267,526,493	25,853,401	9.7
2007	268,279,240	24,788,539	9.2
2008	268,541,088	23,674,017	8.8
2009	268,541,088[a]	23,674,017 [a]	8.8[a]

[a] Assumed equal to 2008 value.

Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized inTable 3-27. Waste incineration CO_2 emissions in 2009 were estimated to be between 9.8 and 15.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2009 emission estimate of 12.3 Tg CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2009 were estimated to be between 0.2 and 1.5 Tg CO_2 Eq. This indicates a range of 51 percent below to 320 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	12.3	9.8	15.2	-21%	+24%
Incineration of Waste	N_2O	0.4	0.2	1.5	-51%	+320%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan was implemented for incineration of waste. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. Formerly, the percentage of overall rubber waste that is synthetic (i.e., fossil-derived rather than biogenic) varied across the product categories, ranging from 25 percent for clothing and footwear to 100 percent synthetic rubber for durable goods and containers and packaging. For the current Inventory, this variable was updated to be 70 percent synthetic rubber for all four waste categories based on an industry average (RMA, 2011). This change resulted in an average 1 percent decrease in CO_2 emissions throughout the time series. In addition, the percentage of waste incinerated was updated for 2008 based on data obtained from The State of Garbage in America report (van Haaren et al., 2010). Because the report is released every other year, the percentage incinerated in 2007 was also updated using linear interpolation from the 2006 and 2008 values. The change in the percentage incinerated, along with the change in the percentage synthetic rubber noted above, decreased the 2007 and 2008 estimates by 4 percent and 7 percent, respectively, relative to the previous report.

Planned Improvements

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

Additional data sources for calculating the N_2O and CH_4 emission factors for U.S. incineration of waste may be investigated.

3.4. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. In 2009, 135 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 23 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2009, 14 coal mines collected CH_4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 13 coal mines sold CH_4 to the natural gas pipeline and one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH_4 to fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2009 were estimated to be 71.0 Tg CO_2 Eq. (3,382 Gg), a decline of 16 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions have generally increased.

Table 3-28: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
UG Mining	62.3	39.4	35.0	35.7	35.7	44.4	50.4
Liberated	67.9	54.4	50.2	54.3	51.0	60.5	67.0
Recovered & Used	(5.6)	(14.9)	(15.1)	(18.7)	(15.3)	(16.1)	(16.5)
Surface Mining	12.0	12.3	13.3	14.0	13.8	14.3	12.9
Post-Mining (UG)	7.7	6.7	6.4	6.3	6.1	6.1	5.6
Post-Mining (Surface)	2.0	2.0	2.2	2.3	2.2	2.3	2.1
Total	**84.1**	**60.4**	**56.9**	**58.2**	**57.9**	**67.1**	**71.0**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-29: CH_4 Emissions from Coal Mining (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
UG Mining	2,968	1,878	1,668	1,699	1,700	2,113	2,401
Liberated	3,234	2,588	2,389	2,588	2,427	2,881	3,189
Recovered & Used	(265.9)	(710.4)	(720.8)	(889.4)	(727.2)	(768.0)	(787.1)
Surface Mining	573.6	585.7	633.1	668.0	658.9	680.5	614.2
Post-Mining (UG)	368.3	318.1	305.9	298.5	289.6	292.0	266.7
Post-Mining (Surface)	93.2	95.2	102.9	108.5	107.1	110.6	99.8
Total	**4,003**	**2,877**	**2,710**	**2,774**	**2,756**	**3,196**	**3,382**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[95] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2009, 13 active coal mines sold recovered CH_4 into the local gas pipeline networks and one coal mine used recovered CH_4 on site for heating. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery

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[95] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2010), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average in situ CH_4 content of the coal. Revised data on in situ CH_4 content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average in situ CH_4 content of coals mined in the basin.

Table 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2000	338,168	635,581	973,749
2005	334,398	691,448	1,025,846
2006	325,697	728,447	1,054,144
2007	319,139	720,023	1,039,162
2008	323,932	737,832	1,061,764
2009	301,241	671,475	972,716

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2009 were estimated to be between 62.0 and 82.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.7 percent below to 16.1 percent above the 2009 emission estimate of 71.0 Tg CO_2 Eq.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Coal Mining	CH_4	71.0	62.0	82.4	-12.7%	+16.1%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, there were some changes to pre-2009 emission estimates relative to the previous Inventory. For the current Inventory, the conversion factor for converting short tons to metric tons was updated to 0.90718474 to be consistent with the number of significant digits used in other source categories. In the past, 0.9072 had been used. The factor was updated for all years, thus coal production estimates in Table 3-31 have changed slightly.

Other changes include the recalculation of emissions avoided for two Jim Walter Resources (JWR) mines: Blue Creek #4 Mine and Blue Creek #7 Mine. This resulted in changes to emissions avoided numbers for 2007 and 2008.

In 1998, 2000, 2001, 2002, 2003, and 2004, the emissions avoided for the Blacksville No. 2 mine in West Virginia were assigned to Pennsylvania rather than West Virginia. These emissions avoided were correctly assigned to West Virginia in the current Inventory; however, total emissions were not affected.

The emissions avoided for the Emerald and Cumberland mines were adjusted going back to 2006 based on information provided by the project developer.

3.5. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2009, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2009, with only ten closures in 2009. By 2009, gross abandoned mine emissions decreased slightly to 8.5 Tg CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 38 mines, resulting in net emissions in 2009 of 5.5 Tg CO_2 Eq.

Table 3-32: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Abandoned Underground Mines	6.0	8.9	7.0	7.6	8.9	9.0	8.5
Recovered & Used	0.0	1.5	1.5	2.2	3.3	3.2	3.0
Total	**6.0**	**7.4**	**5.5**	**5.5**	**5.6**	**5.9**	**5.5**

Note: Totals may not sum due to independent rounding.

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Abandoned Underground Mines	288	422	334	364	425	430	406
Recovered & Used	0	72	70	103	158	150	144
Total	**288**	**350**	**264**	**261**	**267**	**279**	**262**

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, Pr, declines as described by the isotherm. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i\,(1+bD_it)^{(-1/b)}$$

where,

q = Gas rate at time t in mmcf/d
q_i = Initial gas rate at time zero (t_o) in million cubic feet per day mmcfd)
b = The hyperbolic exponent, dimensionless
D_i = Initial decline rate, 1/yr
t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_{ie}^{\ (-Dt)}$$

where,

q = Gas flow rate at time t in mcf/d
q_i = Initial gas flow rate at time zero (t_o) in mcfd

D = Decline rate, 1/yr
t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 − (initial emissions from sealed mine / emission rate at abandonment prior to sealing)). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 469 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 273 of the 469 mines (or 58 percent) is known to be either: (1) vented to the atmosphere; (2) sealed to some degree (either earthen or concrete seals); or, (3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 42 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Table 3-34: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	25	25	48	98	127	224
Illinois	30	3	14	47	25	72
Northern Appl.	42	22	16	80	35	115
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**124**	**53**	**96**	**273**	**196**	**469**

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emission rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 ventilated for the total CH_4 liberation rate for 21 mines that closed between 1992 and 2009. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2009, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: (1) the coal's adsorption isotherm; (2) CH_4 flow capacity as expressed by permeability; and (3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-35. Abandoned coal mines CH_4 emissions in 2009 were estimated to be between 4.0 and 7.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 32 percent above the 2009 emission estimate of 5.5 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 42 percent of the mines), with a ±57 percent uncertainty.

Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Abandoned Underground Coal Mines	CH_4	5.5	4.0	7.3	-27%	+32%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Changes in pre-2009 emissions avoided relative to the previous Inventory are due to the additions of pre-1972 Grayson Hills Energy and DTE Corinth projects, which were added to the current inventory. There were also two abandoned mines added to the current Inventory, one abandoned in 2007 and one in 2008, which resulted in changes in the liberated emissions relative to the previous report.

3.6. Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 221.2 Tg CO_2 Eq. (10,535 Gg) of CH_4 in 2009, a 17 percent increase over 1990 emissions (see Table 3-36 and Table 3-37), and 32.2 Tg CO_2 Eq. (32,171 Gg) of non-combustion CO_2 in 2009, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

CH_4 and non-combustion CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 and non-combustion CO_2 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Emissions from pneumatic devices, well clean-ups, and gas well completions and re-completions with hydraulic fracturing account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from field production accounted for approximately 59 percent of CH_4 emissions and about 34 percent of non-combustion CO_2 emissions from natural gas systems in 2009.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 8 percent of CH_4 emissions and approximately 66 percent of non-combustion CO_2 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 20 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,208,000 miles of distribution mains in 2009, an increase from just over 944,000 miles in 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 percent of CH_4 emissions from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2009 were 13 percent lower than 1990 levels.

Table 3-36: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Field Production	89.2	113.5	105.4	134.0	118.2	122.9	130.3
Processing	18.0	17.7	14.3	14.5	15.1	15.7	17.5
Transmission and Storage	49.2	46.7	41.4	41.0	42.5	43.3	44.4
Distribution	33.4	31.4	29.3	28.3	29.4	29.9	29.0
Total	**189.8**	**209.3**	**190.4**	**217.7**	**205.2**	**211.8**	**221.2**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.

Note: Totals may not sum due to independent rounding.

Table 3-37: CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Field Production	4,248	5,406	5,021	6,380	5,628	5,854	6,205
Processing	855	841	681	689	717	748	834
Transmission and Storage	2,344	2,224	1,973	1,950	2,025	2,062	2,115

Distribution	1,591	1,497	1,395	1,346	1,402	1,423	1,381
Total	**9,038**	**9,968**	**9,069**	**10,364**	**9,771**	**10,087**	**10,535**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-38: Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Field Production	9.7	6.4	8.0	9.4	9.7	11.3	10.9
Processing	27.8	23.3	21.7	21.2	21.2	21.4	21.2
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+
Total	**37.6**	**29.9**	**29.9**	**30.8**	**31.1**	**32.8**	**32.2**

Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 Tg CO_2 Eq.

Table 3-39: Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Field Production	9,704	6,425	8,050	9,438	9,746	11,336	10,877
Processing	27,763	23,343	21,746	21,214	21,199	21,385	21,189
Transmission and Storage	62	64	64	63	64	65	65
Distribution	46	44	41	40	41	42	41
Total	**37,574**	**29,877**	**29,902**	**30,755**	**31,050**	**32,828**	**32,171**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and non-combustion CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-combustion CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

Although the inventory primarily uses EPA/GRI emission factors, significant improvements were made to the emissions estimates for three sources this year: gas well cleanups, condensate storage tanks and centrifugal compressors. In addition, data for two sources not included in the EPA/GRI study – gas well completions and gas well workovers (re-completions) with hydraulic fracturing- was added this year. In the case of gas well cleanups, the methodology was revised to use a large sample of well and reservoir characteristics from the HPDI database (HPDI 2009) along with an engineering statics equation (EPA 2006a) to estimate the volume of natural gas necessary to expel a liquid column choking the well production. The same sample E&P Tank sample runs for condensate tank flashing emissions was used; however, the factor was improved by using a large sample distribution of condensate production by gravity from the HPDI database (HPDI 2009) to weigh the sample simulation flashing emissions rather than assuming a uniform distribution of condensate gravities. Additionally, TERC (TERC 2009) data representing two regions was used in the emission factors for those two regions to estimate the effects of separator dump valves malfunctioning and allowing natural gas to vent through the downstream storage tanks. The EPA/GRI emission factor for centrifugal compressors sampled emissions at the seal face of wet seal compressors. A World Gas Conference publication (WGC 2009) on the seal oil degassing vents was used to update this factor and to also account for the emergence of dry seal centrifugal compressors (EPA 2006b), which eliminates seal oil degassing vents and reduces overall emissions. Gas well completions and workovers with hydraulic fracturing were not common at the time the EPA/GRI survey was conducted. Since then, emissions data has become available through Natural Gas STAR experiences and presentations (EPA 2004, 2007) as these activities became more prevalent. The EPA/GRI study and previous Inventories did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring. The changes for gas well cleanups, condensate storage tanks, centrifugal compressors, and gas well completions and gas well workovers (re-completions) with hydraulic fracturing are described below in the Recalculations section. See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors and adjust CH_4 emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the methane composition for each NEMS oil and gas supply module region. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The @RISK model utilizes 1992 (base year) emissions to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2009.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2009. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH_4 emissions in 2009 were estimated to be between 179.1 and 287.6 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2009 were estimated to be between 26.1 and 41.9 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[c]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]

Natural Gas Systems	CH_4	221.2	179.1	287.6	-19%	+30%
Natural Gas Systems[b]	CO_2	32.2	26.1	41.9	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

[b] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.

[c] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

A number of potential data sources were investigated to improve selected emission factors in the natural gas industry. First, the HPDI database for well production and well properties was investigated for potential engineering parameters to be used in engineering equations to develop a new emission factor for well cleanups (HPDI 2009). The database was queried to obtain average well depth, shut-in pressure, well counts, and well production from each basin. These parameters were used along with industry experiences to develop an engineering estimate of emissions from each well in each basin of the sample data. The analysis led to a new emission factor for the gas well cleanup source.

Additionally, industry experiences with hydraulic fracturing of tight formations for the completion or workover of natural gas wells were reviewed to account for this source of emissions. Several Partners of the Natural Gas STAR Program have reported recovering substantial volumes of natural gas that would have otherwise been vented following completions or re-completions (workovers) involving hydraulic fracturing. This completion method, which is a large emission source, was not characterized by the base EPA/GRI 1996 study and has not been accounted for in the national Inventory until this year.

A World Gas Conference paper (WGC 2009) gathered 48 sample measurements of centrifugal compressor wet seal oil degassing emissions and published the results. The base year EPA/GRI 1996 study did not measure emissions from the seal oil degassing vent. Instead seal face emissions were quantified and as such this emission source has gone uncharacterized in the national Inventory until this year.

In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. These data were included where available for the Inventory. More data will be necessary to potentially separate this source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

A number of other data sources for fugitive emission factors from the processing and transmission and storage segments were reviewed. Several studies have been published since the EPA/GRI 1996 base year study that sample emissions from the same common equipment components. The raw emissions data from these surveys can potentially be combined with the raw data from the base year study to develop stronger emission factors. In addition to common component leaks, several of these studies propose emission factors for pneumatic devices or other sources. These studies require further review and thus the data are not included in the Inventory at this time.

Recalculations Discussion

Methodologies for gas well cleanups and condensate storage tanks were revised for the current Inventory, and new sources of data for centrifugal compressors with wet seals, gas well completions with hydraulic fracturing, and gas well workovers with hydraulic fracturing were used.

The largest increase in emissions relative to the previous Inventory was due to the revised emission factor for gas well cleanups (also referred to in industry as gas well liquids unloading). HPDI well production and well property sample data on well depth, shut-in pressure, and production rates were used in an engineering equation to re-estimate the average unloading emissions by NEMS oil and gas module region for this source (HPDI 2009). This methodological change increased emissions by more than 22 times while decreasing the substantial uncertainty that was associated with the previous emission factor from the EPA/GRI 1996 study. The activity data remained the same as the previous methodology. Emissions from non-Gas STAR Partners were not considered, nor was an independent estimate of the scope of those emissions accounted for. Reductions beyond those reported from Natural

Gas STAR Partners will be considered for inclusion in the next Inventory of sufficient data are available.

The next largest increase in emissions was due to the inclusion of gas well completions and workovers involving hydraulic fracture (i.e. unconventional completions and workovers). The EPA/GRI 1996 study did not account for this emerging technology and the source was previously unaccounted for in the Inventory. The Inventory did account for completion flaring, however, this only includes emissions from completions without hydraulic fracturing (i.e. conventional completions), which the EPA/GRI 1996 study assumes are mostly flared. Unlike completions and workovers without hydraulic fracturing (i.e. conventional workovers), the high pressure venting of gas in order to expel the large volumes of liquid used to fracture the well formation, results in a large emission of natural gas. The Inventory tracks activity data for wells completed with hydraulic fracturing in each region. The gas well completions with hydraulic fracturing was approximated using total number of producing gas wells completed with hydraulic fracturing and the total number of shut-in gas wells completed with hydraulic fracturing from each year. This approximation is made by taking the difference between the number of unconventional wells reported by EIA for the current year and the previous year. Since drilling and hydraulic fracturing in unconventional (e.g. shale, tight, and coal bed methane) formations is a relatively new technology, it is assumed that zero gas wells completed with hydraulic fracturing are shut-in each year. This activity data was used along with a newly developed emission factor to estimate emissions from these sources. It was assumed that approximately 50 percent of emissions from gas well completions and workovers with hydraulic fracturing would be flared due to states such as Wyoming that do not permit the venting of natural gas during well completions.

The same E&P Tank simulation data for hydrocarbon liquids above 45˚API flashing emission in tanks was used as in previous Inventories to estimate emissions from condensate tanks; however, these flashing emissions simulations were coupled with a large sample of condensate production gravities from the HPDI database to improve the factor to account for the average national distribution of condensate gravities. Previously, a simple average of simulation results for each liquid gravity was used. Additionally, the TERC (2009) study provided a small sample of data representing two regions in Texas where separator dump valve malfunctions were detected and measured. This data was applied only to the regions represented by the study to account for this emission source.

Finally, WGC (2009) sample data on centrifugal compressor seal oil degassing vent rates was used to divide the centrifugal compressors source in the processing and transmission and storage segments into two sources—centrifugal compressors equipped with wet seals and centrifugal compressors equipped with dry seals. The seal oil degassing vent (found with compressors using wet seals) was previously unaccounted for in the Inventory. This improved methodology accounted for an increase in emissions from these sources between 50 and 100 percent.

Finally, the previous Inventory activity data are updated with revised values each year. However, the impact of these changes was small compared to the changes described above.

The net effect of these changes was to increase total CH_4 emissions from natural gas systems between 47 and 120 percent each year between 1990 and 2008 relative to the previous report. The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of gas well completions and workovers with hydraulic fracturing.

Planned Improvements

Emission reductions reported to Natural Gas STAR are deducted from the total sector emissions each year in the natural gas systems inventory model to estimate emissions. These reported reductions often rely on Inventory emission factors to quantify the extent of reductions. These reductions are also a source of uncertainty that is not currently analyzed in the Inventory. Emissions reductions—in particular from gas well cleanups—may be underestimated, and we intend to investigate whether additional data are available, and if appropriate, revisions to more accurately account for emissions from natural gas systems will be incorporated into future inventories. Additionally, accounting for the uncertainty of these reductions to more accurately provide upper and lower bounds within the 95 percent confidence interval, will be investigated.

Separately, a larger study is currently underway to update selected compressor emission factors used in the national inventory. Most of the activity factors and emission factors in the natural gas inventory are from the EPA/GRI (1996) study. The current measurement-based study to develop updated emission factors for compressors is intended to better reflect current national circumstances. Results from these studies are expected in 2011, and will be incorporated into the Inventory, pending a peer review.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as it becomes available on this emissions source and emissions will be updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule, Subpart W) will be reviewed for potential improvements to the natural gas systems emissions estimates. The rule will collect actual activity data using improved quantification methods from those used in several of the studies which form the basis of this Inventory. Data collection for Subpart W began January 1, 2011 with emissions reporting beginning in 2012. These base year 2011 data will be reviewed for inclusion into a future Inventory to improve the accuracy and reduce the uncertainty of the emission estimates.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Combusted CO_2 emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH_4 and CO_2 emissions from petroleum systems in 2009 were 30.9 Tg CO_2 Eq. (1,473 Gg CH_4) and 0.5 Tg CO_2 (463 Gg), respectively. Since 1990, CH_4 emissions have declined by 13 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-41and Table 3-42). CO_2 emissions have also declined by 17 percent since 1990 due to similar reasons (see Table 3-43 and Table 3-44).

Production Field Operations. Production field operations account for about 98 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for over 90 percent of the emissions from the production sector, unburned CH_4 combustion emissions account for 6.4 percent, fugitive emissions are 3.4 percent, and process upset emissions are slightly under two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from oil tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining six percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level data on CH_4 emissions in production field operations, refer to Annex 3.5.

Vented CO_2 associated with natural gas emissions from field operations account for 99 percent of the total CO_2 emissions from this source category, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions from this source category, while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 61 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 20 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly less than two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented emissions account for about 86 percent of the emissions, while both fugitive and combustion emissions account for approximately seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Asphalt blowing from crude oil refining accounts for 36 percent of the total non-combustion CO_2 emissions in petroleum systems.

Table 3-41: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Production Field Operations	**34.7**	**30.8**	**28.7**	**28.7**	**29.3**	**29.6**	**30.3**
Pneumatic device venting	10.3	9.0	8.4	8.3	8.4	8.7	8.8
Tank venting	5.3	4.5	3.9	3.9	4.0	4.0	4.5
Combustion & process upsets	1.9	1.6	1.5	1.5	1.5	1.6	2.0
Misc. venting & fugitives	16.8	15.3	14.5	14.6	15.0	14.8	14.6
Wellhead fugitives	0.6	0.5	0.4	0.4	0.4	0.5	0.5
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**
Total	**35.4**	**31.5**	**29.4**	**29.4**	**30.0**	**30.2**	**30.9**

Note: Totals may not sum due to independent rounding.

Table 3-42: CH_4 Emissions from Petroleum Systems (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Production Field Operations	**1,653**	**1,468**	**1,366**	**1,365**	**1,396**	**1,409**	**1,444**
Pneumatic device venting	489	428	397	396	398	416	419
Tank venting	250	214	187	188	192	189	212
Combustion & process upsets	88	76	71	71	72	75	94
Misc. venting & fugitives	799	727	691	693	714	707	696
Wellhead fugitives	26	22	19	17	20	23	23
Crude Oil Transportation	**7**	**5**	**5**	**5**	**5**	**5**	**5**
Refining	**25**	**28**	**28**	**28**	**27**	**25**	**24**
Total	**1,685**	**1,501**	**1,398**	**1,398**	**1,427**	**1,439**	**1,473**

Note: Totals may not sum due to independent rounding.

Table 3-43: CO_2 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Production Field Operations	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Pneumatic device venting	+	+	+	+	+	+	+
Tank venting	0.3	0.3	0.2	0.2	0.3	0.2	0.3
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Crude Refining	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**
Total	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-44: CO_2 Emissions from Petroleum Systems (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Production Field Operations	**376**	**323**	**285**	**285**	**292**	**288**	**319**
Pneumatic device venting	27	24	22	22	22	23	23
Tank venting	328	281	246	246	252	247	278
Misc. venting & fugitives	18	17	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1
Crude Refining	**180**	**211**	**205**	**203**	**182**	**165**	**144**
Total	**555**	**534**	**490**	**488**	**474**	**453**	**463**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity factors for the years 1990 through 2009 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, BOEMRE 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2009. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2010a-c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2009).

For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2009 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2010, 1995 through 2010, 1995 through 2010a-b), Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA (EPA/GRI 1996a-d), Estimates of Methane Emissions from the U.S. Oil Industry (EPA 1999), consensus of industry peer review panels, BOEMRE reports (BOEMRE 2005, 2010a-c), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2010a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2008), and the United States Army Corps of Engineers (1995-2008).

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO_2 are estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up Inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Petroleum systems CH_4 emissions in 2009 were estimated to be between 23.5 and 76.9 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.4 and 1.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2009 emission estimates of 30.9 and 0.5 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound[b]	**Upper Bound**[b]	**Lower Bound**[b]	**Upper Bound**[b]
Petroleum Systems	CH_4	30.9	23.5	76.9	-24%	149%
Petroleum Systems	CO_2	0.5	0.4	1.2	-24%	149%

[a] Range of 2009 relative uncertainty predicted by Monte Carlo Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.

[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Note: Totals may not sum due to independent rounding

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

As part of QA/QC and verification activities done for the Inventory, potential improvements were identified, which include a new emissions source associated with fixed roof storage tank emissions in the production segment. In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. This data was included where available for the Inventory (see Recalculation discussion below). More data will be necessary to potentially add this as a separate source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

Recalculations Discussion

Most revisions for the current Inventory relative to the previous report were due to updating previous years' data with revised data from existing data sources. Well completion venting, well drilling, and offshore platform activity factors were updated from existing data sources from 1990 onward.

Additionally, the emission factor for venting from fixed roof storage tanks in the crude oil production segment was revised. Using the same E&P Tank sample data runs on crude oil gravities ranging up to 45˚API, a new national level flashing emissions factor was developed by using a large sample of production data, sorted by gravity, available from the HPDI database.

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas (TERC 2009). This data was plotted and compared to the flashing emissions simulated via E&P Tank simulation. EPA observed that additional emissions beyond the flashing were present in approximately 50 percent of the tanks. These emissions may be attributed to separator dump valves malfunctioning or other methods of associated gas entering the tank and venting from the roof. Because the dataset was limited to represent production from only 14 counties that represent 0.5 percent of U.S. production, the national emission factor was scaled up such that only production from these counties is affected by the occurrence of associated gas venting through the storage tank.

Planned Improvements

As noted above, nearly all emission factors used in the development of the petroleum systems estimates were taken from EPA (1995, 1996, 1999), with the remaining emission factors taken from EPA default values (EPA 2005) and a consensus of industry peer review panels. These emission factors will be reviewed as part of future Inventory work. Results of this review and analysis will be incorporated into future inventories, as appropriate.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as they become available on this emissions source and emissions updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program will be reviewed for potential improvements to petroleum systems emissions sources. The rule will collect actual activity data and improved quantification methods from those used in several of the studies which form the basis of this Inventory. This data will be incorporated as appropriate into the current Inventory to improve the accuracy and uncertainty of the emissions estimates. In particular, EPA will investigate whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems inventory (e.g., CO_2 process emissions from hydrogen production).

In 2010, all U.S. petroleum refineries were required to collect information on their greenhouse gas emissions. This data will be reported to EPA through its Greenhouse Gas Reporting Program in 2011. Data collected under this program will be evaluated for use in future inventories to improve the calculation of national emissions from petroleum systems.

[BEGIN BOX]

Box 3-3. Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC (IPCC, 2006) included, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC, 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO_2 emissions estimates for geologic storage.

Beginning in 2010, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground will be required to calculate and report greenhouse gas data annually to EPA through its Greenhouse

Gas Reporting Program. The Greenhouse Gas Reporting Rule requires greenhouse gas reporting from facilities that inject CO_2 underground for geologic sequestration, and requires greenhouse gas reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Beginning in 2010, facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program, which will be reported to EPA in early 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain, EPA intends to evaluate that information closely and consider opportunities for improving our current inventory estimates.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 47.3 Tg CO_2 (47,340 Gg CO_2) (see Table 3-46 and Table 3-47). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted.

Table 3-46: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Acid Gas Removal Plants	4.8	2.3	5.8	6.2	6.4	6.6	7.0
Naturally Occurring CO_2	20.8	23.2	28.3	30.2	33.1	36.1	39.7
Ammonia Production Plants	+	0.7	0.7	0.7	0.7	0.6	0.6
Pipelines Transporting CO_2	+	+	+	+	+	+	+
Total	**25.6**	**26.1**	**34.7**	**37.1**	**40.1**	**43.3**	**47.3**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note; Totals may not sum due to independent rounding.

Table 3-47: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Acid Gas Removal Plants	4,832	2,264	5,798	6,224	6,088	6,630	7,035
Naturally Occurring CO_2	20,811	23,208	28,267	30,224	33,086	36,102	39,725
Ammonia Production Plants	+	676	676	676	676	580	580
Pipelines Transporting CO_2	8	8	7	7	7	8	8
Total	**25,643**	**26,149**	**34,742**	**37,124**	**40,141**	**43,311**	**47,340**

+ Does not exceed 0.5 Gg.
Note: Totals do not include emissions from pipelines transporting CO_2
Note; Totals may not sum due to independent rounding.

[END BOX]

3.8. *Energy Sources of Indirect Greenhouse Gas Emissions*

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2009 are reported in Table 3-48.

Table 3-48: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
NO_x	**21,106**	**18,477**	**15,319**	**14,473**	**13,829**	**13,012**	**10,887**
Mobile Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
*International Bunker Fuels**	*2,020*	*1,344*	*1,703*	*1,793*	*1,791*	*1,917*	*1,651*
CO	**125,640**	**89,714**	**69,062**	**65,399**	**61,739**	**58,078**	**49,647**
Mobile Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543

Incineration of Waste	978		1,670		1,403	1,412	1,421	1,430	1,403
Oil and Gas Activities	302		146		318	319	320	322	345
*International Bunker Fuels**	*130*		*128*		*132*	*161*	*160*	*165*	*149*
NMVOCs	**12,620**		**8,952**		**7,798**	**7,702**	**7,604**	**7,507**	**5,333**
Mobile Combustion	10,932		7,229		6,330	6,037	5,742	5,447	4,151
Stationary Combustion	912		1,077		716	918	1,120	1,321	424
Oil and Gas Activities	554		388		510	510	509	509	599
Incineration of Waste	222		257		241	238	234	230	159
*International Bunker Fuels**	*61*		*45*		*54*	*59*	*59*	*62*	*57*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[96] These decisions are reflected in the IPCC methodological guidance, including the 2006 IPCC Guidelines, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).[97]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[98] Emissions from ground transport activities—by road vehicles and trains—even when crossing

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[96] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

[97] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[98] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation

international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[99]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2009 from the combustion of international bunker fuels from both aviation and marine activities were 124.4 Tg CO_2 Eq., or ten percent above emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 49 percent and decreased by 18 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-49: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**111.8**	**98.5**	**109.7**	**128.4**	**127.6**	**133.7**	**123.1**
Aviation	46.4	58.8	56.7	74.6	73.8	75.5	69.4
Marine	65.4	39.7	53.0	53.8	53.9	58.2	53.7
CH_4	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.1**	**0.9**	**1.0**	**1.2**	**1.2**	**1.2**	**1.1**
Aviation	0.5	0.6	0.6	0.8	0.8	0.8	0.7
Marine	0.5	0.3	0.4	0.4	0.4	0.5	0.4
Total	**113.0**	**99.5**	**110.9**	**129.7**	**129.0**	**135.1**	**124.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-50: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**111,828**	**98,482**	**109,750**	**128,384**	**127,618**	**133,704**	**123,127**
Aviation	46,399	58,785	56,736	74,552	73,762	75,508	69,404
Marine	65,429	39,697	53,014	53,832	53,856	58,196	53,723
CH_4	**8**	**6**	**7**	**8**	**8**	**8**	**7**
Aviation	2	2	2	2	2	2	2

Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

[99] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

Marine	7	4	5	5	5	6	5
N_2O	**3**	**3**	**3**	**4**	**4**	**4**	**4**
Aviation	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model (FAA 2006). That tool has been subsequently replaced by the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for flights globally in a given year (FAA 2010). Data for inventory years 2006 through 2009 were developed using AEDT.

International aviation bunker fuel consumption from 1990 to 2009 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010). Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2011). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-51. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2010) for 1990 through 2001, 2007, through 2009, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2011). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in. Table 3-52.

Table 3-51: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

U.S. and Foreign Carriers	4,934	6,157	5,943	7,809	7,726	7,909	7,270
U.S. Military	862	480	462	400	410	386	368
Total	**5,796**	**6,638**	**6,405**	**8,209**	**8,137**	**8,295**	**7,638**

Note: Totals may not sum due to independent rounding.

Table 3-52: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Residual Fuel Oil	4,781	2,967	3,881	4,004	4,059	4,373	4,040
Distillate Diesel Fuel & Other	617	290	444	446	358	445	426
U.S. Military Naval Fuels	522	329	471	414	444	437	384
Total	**5,920**	**3,586**	**4,796**	**4,864**	**4,861**	**5,254**	**4,850**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[100] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the Revised 1996 IPCC Guidelines is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

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[100] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

near-ground level emissions of gases other than CO_2.[101]

There is also concern as to the reliability of the existing DOC (1991 through 2010) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2008 relative to the previous Inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.13 Tg CO_2 Eq. (0.1 percent) in CO_2 emissions, an annual decrease of less than 0.01 Tg CO_2 Eq. (0.05 percent) in CH_4 emissions, and an annual decrease of less than 0.01 Tg CO_2 Eq. (0.1 percent) in N_2O emissions.

3.10. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol from corn and woody crops generates CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 7), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2009, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 183.8 Tg CO_2 Eq. (183,777 Gg) (see Table 3-53 and Table 3-54). As the largest consumer of woody biomass, the industrial sector was responsible for 62 percent of the CO_2 emissions from this source. Emissions from this sector decreased from 2008 to 2009 due to a corresponding decrease in wood consumption. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-53: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Industrial	135.3	153.6	136.3	138.2	132.6	126.1	114.2
Residential	59.8	43.3	44.3	40.2	44.3	46.4	44.3

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[101] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Commercial	6.8	7.4	7.2	6.7	7.2	7.5	7.4
Electricity Generation	13.3	13.9	19.1	18.7	19.2	18.3	17.8
Total	**215.2**	**218.1**	**206.9**	**203.8**	**203.3**	**198.4**	**183.8**

Note: Totals may not sum due to independent rounding.

Table 3-54: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135,348	153,559	136,269	138,207	132,642	126,145	114,222
Residential	59,808	43,309	44,340	40,215	44,340	46,402	44,340
Commercial	6,779	7,370	7,182	6,675	7,159	7,526	7,406
Electricity Generation	13,252	13,851	19,074	18,748	19,175	18,288	17,809
Total	**215,186**	**218,088**	**206,865**	**203,846**	**203,316**	**198,361**	**183,777**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles.

In 2009, the United States consumed an estimated 894 trillion Btu of ethanol, and as a result, produced approximately 61.2 Tg CO_2 Eq. (61,231 Gg) (see Table 3-55 and Table 3-56) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-55: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	4.1	9.2	22.4	30.3	38.1	53.8	60.2
Industrial	0.1	0.1	0.5	0.7	0.7	0.8	0.9
Commercial	+	+	0.1	0.1	0.1	0.1	0.2
Total	**4.2**	**9.4**	**23.0**	**31.0**	**38.9**	**54.8**	**61.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-56: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation[a]	4,139	9,239	22,427	30,255	38,138	53,827	60,176
Industrial	56	87	469	662	674	798	892
Commercial	34	26	60	86	135	146	163
Total	**4,229**	**9,352**	**22,956**	**31,002**	**38,946**	**54,770**	**61,231**

[a] See Annex 3.2, Table A-88 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2010) (see Table 3-57), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2010) (see Table 3-58).

Table 3-57: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	1,442	1,636	1,452	1,472	1,413	1,344	1,217

Residential	580	420	430	390	430	450	430
Commercial	66	71	70	65	69	73	72
Electricity Generation	129	134	185	182	186	177	173
Total	**2,216**	**2,262**	**2,136**	**2,109**	**2,098**	**2,044**	**1,891**

Table 3-58: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	60.5	135.0	327.6	442.0	557.1	786.3	879.0
Industrial	0.8	1.3	6.8	9.7	9.8	11.7	13.0
Commercial	0.5	0.4	0.9	1.3	2.0	2.1	2.4
Total	**61.8**	**136.6**	**335.3**	**452.9**	**568.9**	**800.1**	**894.5**

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values were revised for 2006 through 2008 based on updated information from EIA's Annual Energy Review (EIA 2010). This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of 0.8 Tg CO_2 Eq. (0.4 percent) from 1990 through 2008. The C content coefficient for ethanol was also revised to be consistent with the carbon content coefficients used for EPA's Mandatory Greenhouse Gas Reporting Rule. Slight adjustments were made to ethanol consumption based on updated information from EIA (2010), which slightly decreased estimates for ethanol consumed. As a result of these adjustments, average annual emissions from ethanol consumption increased by about 0.3 Tg CO_2 Eq. (1.9 percent) relative to the previous Inventory.

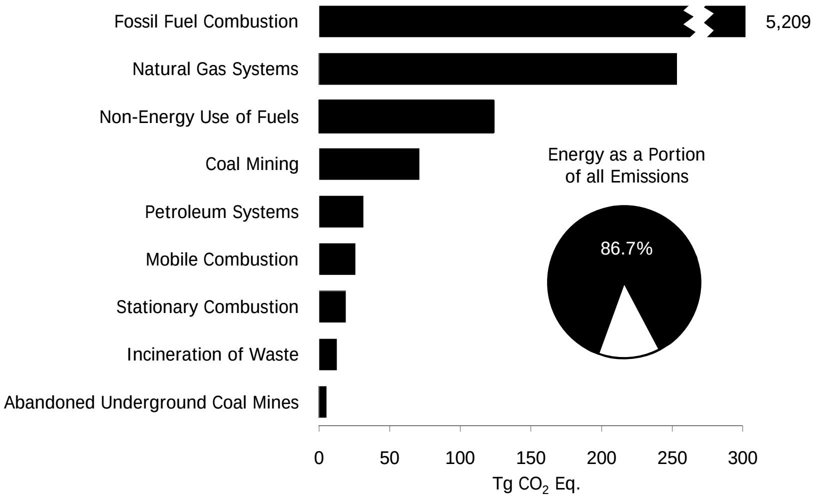
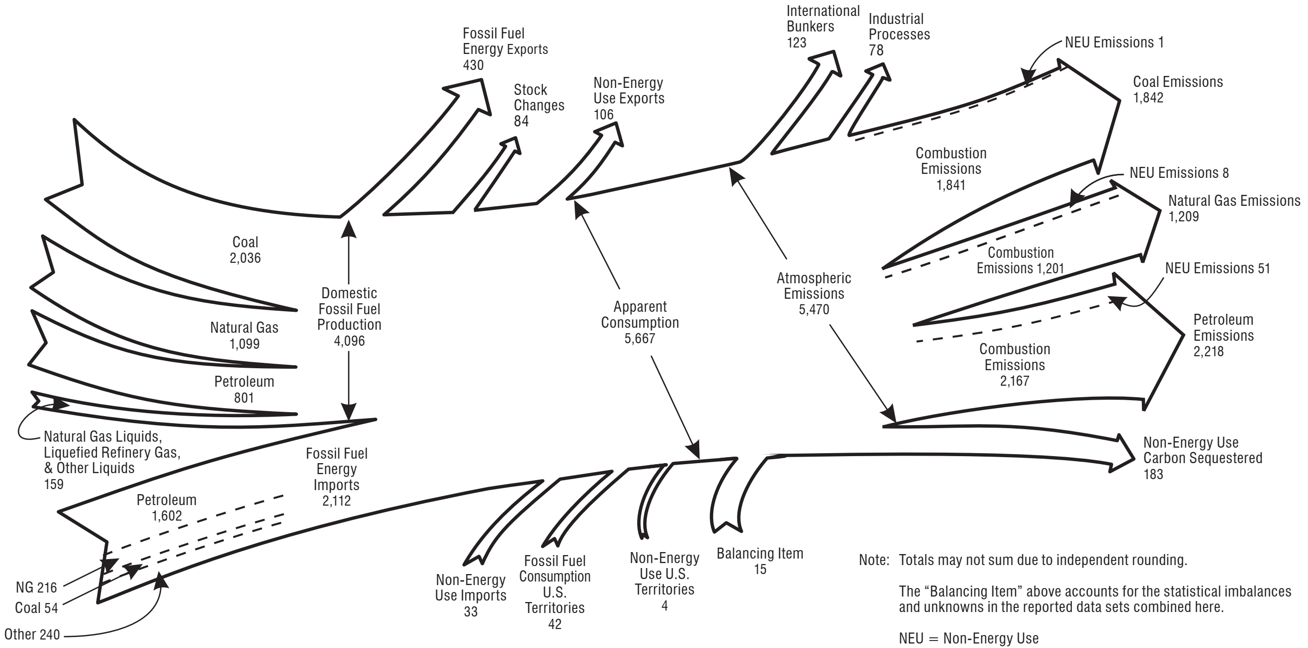


Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources



Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

Figure 3-2 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

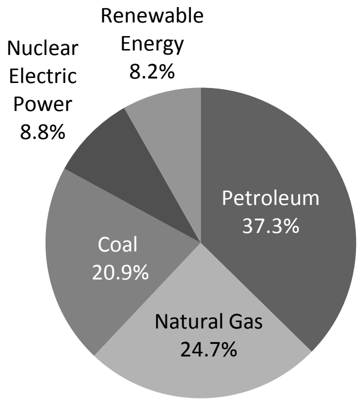


Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

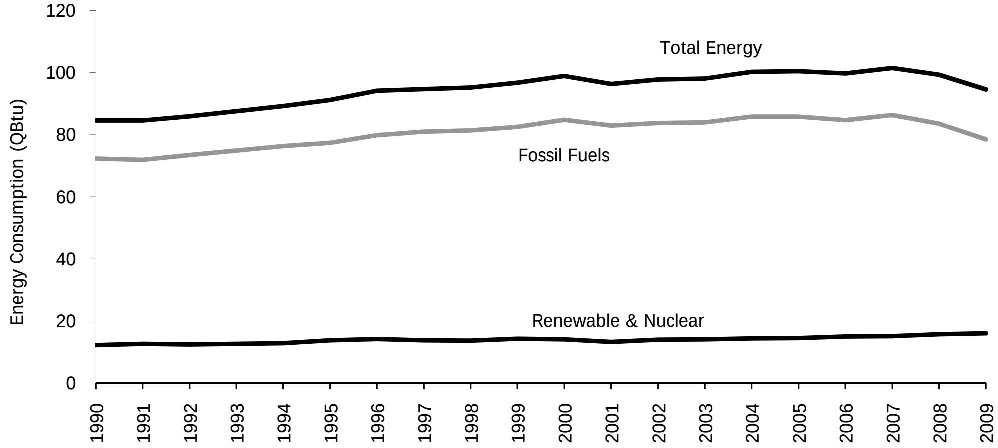


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Note: Expressed as gross calorific values.

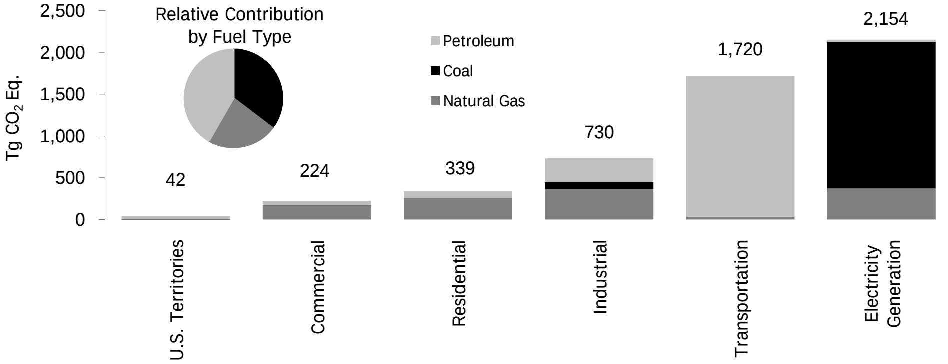


Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

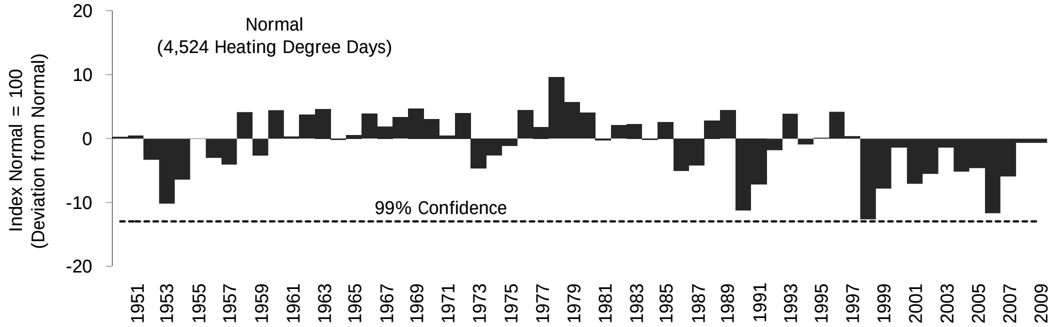


Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

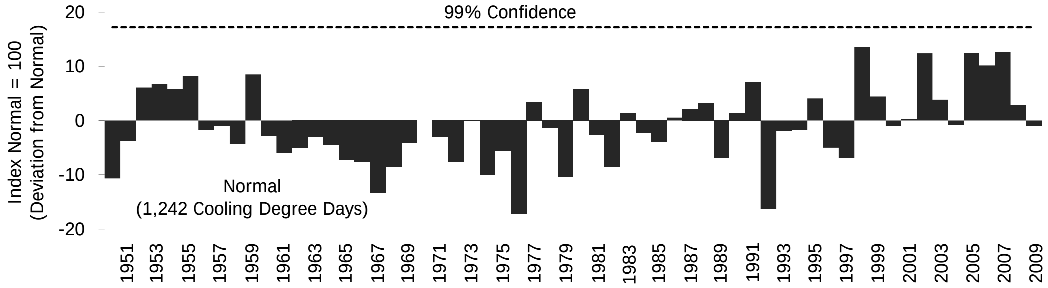


Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

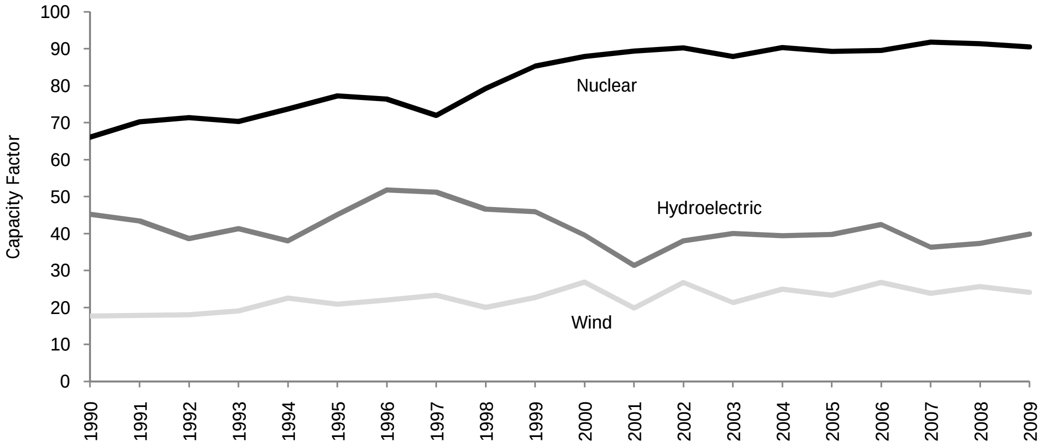


Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2009)

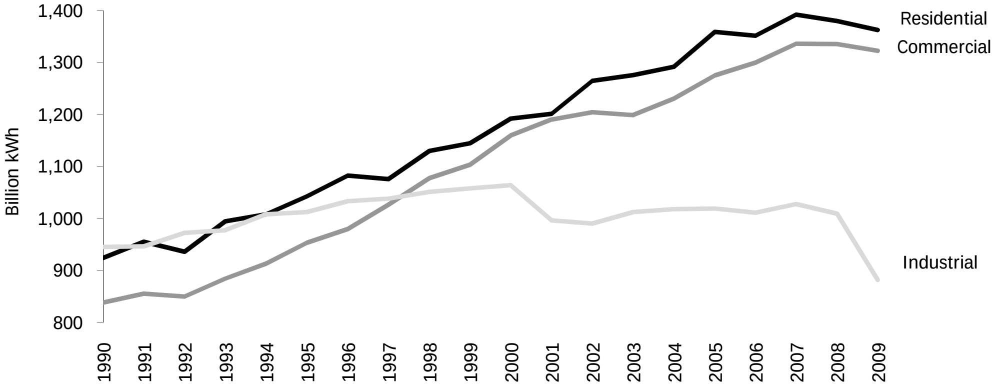


Figure 3-9: Electric Generation Retail Sales by End-Use Sector

Note: The transportation end-use sector consumes minor quanties of electricity.

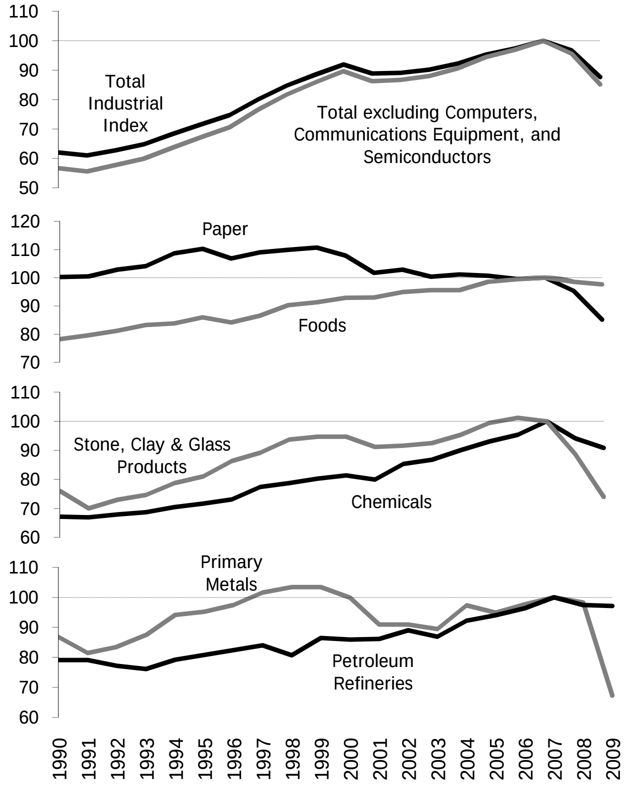


Figure 3-10: Industrial Production Indexes (Index 2007=100)

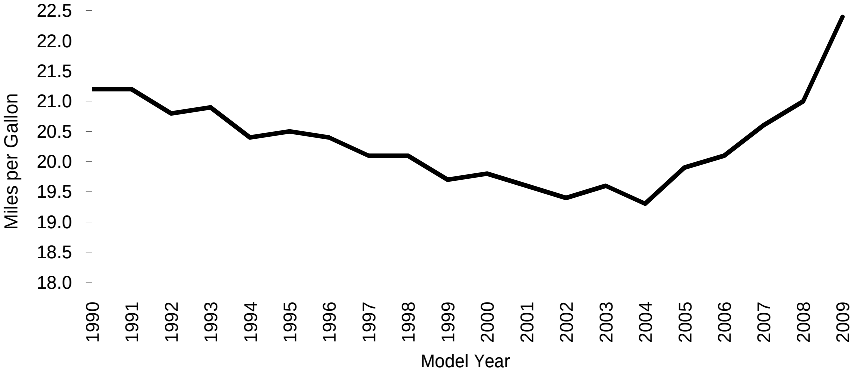


Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2009

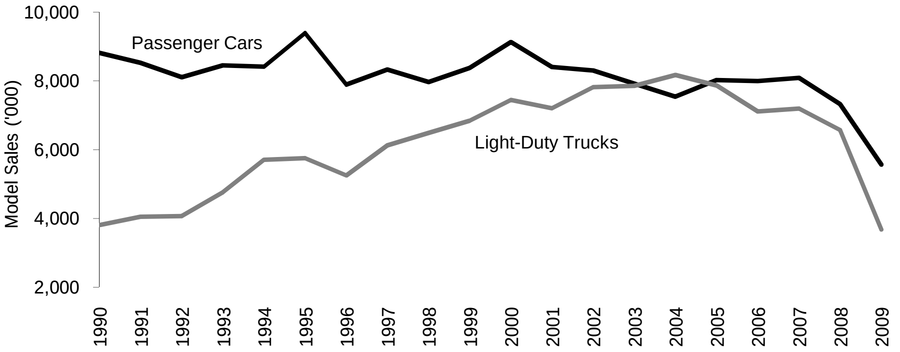


Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2009

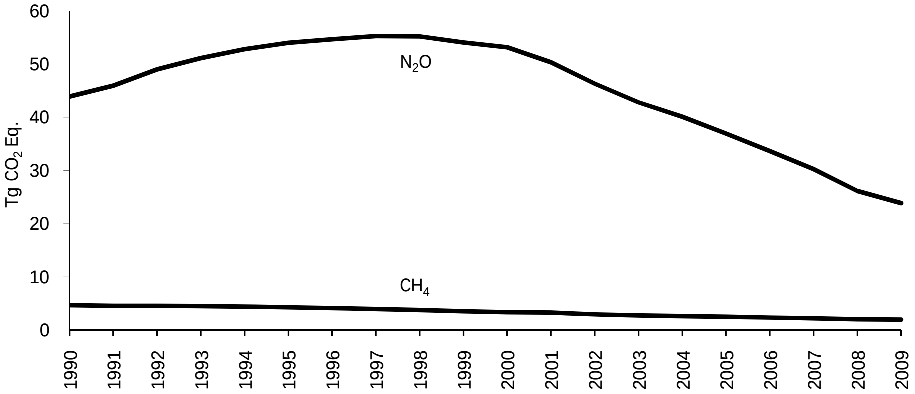


Figure 3-13: Mobile Source CH_4 and N_2O Emissions

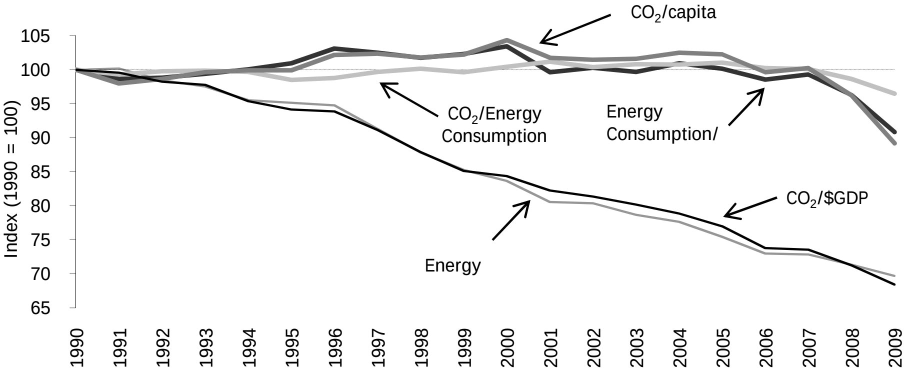


Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

4. Industrial Processes

Greenhouse gas emissions are produced as the by-products of various non-energy-related industrial activities. That is, these emissions are produced from an industrial process itself and are not directly a result of energy consumed during the process. For example, raw materials can be chemically transformed from one state to another. This transformation can result in the release of greenhouse gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The processes addressed in this chapter include iron and steel production and metallurgical coke production, cement production, lime production, ammonia production and urea consumption, limestone and dolomite consumption (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and use, aluminum production, titanium dioxide production, CO_2 consumption, ferroalloy production, phosphoric acid production, zinc production, lead production, petrochemical production, silicon carbide production and consumption, nitric acid production, and adipic acid production (see Figure 4-1).

Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

In addition to the three greenhouse gases listed above, there are also industrial sources of man-made fluorinated compounds called hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The present contribution of these gases to the radiative forcing effect of all anthropogenic greenhouse gases is small; however, because of their extremely long lifetimes, many of them will continue to accumulate in the atmosphere as long as emissions continue. In addition, many of these gases have high global warming potentials; SF_6 is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC) has evaluated. Usage of HFCs is growing rapidly since they are the primary substitutes for ozone depleting substances (ODSs), which are being phased-out under the Montreal Protocol on Substances that Deplete the Ozone Layer. In addition to their use as ODS substitutes, HFCs, PFCs, and SF_6 are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing.

In 2009, industrial processes generated emissions of 282.9 teragrams of CO_2 equivalent (Tg CO_2 Eq.), or 4 percent of total U.S. greenhouse gas emissions. CO_2 emissions from all industrial processes were 119.0 Tg CO_2 Eq. (119,010 Gg) in 2009, or 2 percent of total U.S. CO_2 emissions. CH_4 emissions from industrial processes resulted in emissions of approximately 1.2 Tg CO_2 Eq. (58 Gg) in 2009, which was less than 1 percent of U.S. CH_4 emissions. N_2O emissions from adipic acid and nitric acid production were 16.5 Tg CO_2 Eq. (53 Gg) in 2009, or 6 percent of total U.S. N_2O emissions. In 2009 combined emissions of HFCs, PFCs and SF_6 totaled 146.1 Tg CO_2 Eq. Despite the significant increase in HFC emissions associated with increased usage of ODSs, total emissions from industrial processes in 2009 were less than 1990 for the first time since 1994. This decrease is primarily due to significant reductions in emissions from iron and steel production, metallurgical coke production, ammonia production and urea consumption, adipic acid production, HCFC-22 production, aluminum production and cement production.

Table 4-1 summarizes emissions for the Industrial Processes chapter in Tg CO_2 Eq., while unweighted native gas emissions in Gg are provided in Table 4-2. The source descriptions that follow in the chapter are presented in the order as reported to the UNFCCC in the common reporting format tables, corresponding generally to: mineral products, chemical production, metal production, and emissions from the uses of HFCs, PFCs, and SF_6.

Table 4-1: Emissions from Industrial Processes (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**188.4**	**184.9**	**165.4**	**169.9**	**172.6**	**159.5**	**119.0**
Iron and Steel Production an Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Iron and Steel Productio	*97.1*	*83.7*	*63.9*	*66.9*	*69.0*	*63.7*	*40.9*
Metallurgical Coke Production	*2.5*	*2.2*	*2.0*	*1.9*	*2.1*	*2.3*	*1.0*
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Ure Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8

Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Us	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumptio	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Productio	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	**1.9**	**2.2**	**1.8**	**1.7**	**1.7**	**1.6**	**1.2**
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production an Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Iron and Steel Productio	*1.0*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.4*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N_2O	**33.5**	**24.9**	**21.5**	**20.5**	**22.9**	**18.5**	**16.5**
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	**36.9**	**103.2**	**120.2**	**123.5**	**129.5**	**129.4**	**125.7**
Substitution of Ozone Depleting Substances[a]	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacturi HFCs	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	**20.8**	**13.5**	**6.2**	**6.0**	**7.5**	**6.7**	**5.6**
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
Semiconductor Manufacturi PFCs	2.2	4.9	3.2	3.5	3.7	4.0	4.0
SF_6	**34.4**	**20.1**	**19.0**	**17.9**	**16.7**	**16.1**	**14.8**
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Semiconductor Manufacturi SF_6	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Total	**315.8**	**348.8**	**334.1**	**339.4**	**350.9**	**331.7**	**282.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

[a] Small amounts of PFC emissions also result from this source.

Table 4-2: Emissions from Industrial Processes (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**188,431**	**184,919**	**165,384**	**169,870**	**172,592**	**159,470**	**119,010**
Iron and Steel Production and Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871

Iron and Steel Production	*97,058*	*83,740*	*63,882*	*66,852*	*68,991*	*63,682*	*40,914*
Metallurgical Coke Production	*2,470*	*2,195*	*2,043*	*1,919*	*2,054*	*2,334*	*956*
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Ammonia Production & Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966
Lead Production	516	594	553	560	562	551	525
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
CH_4	**88**	**104**	**86**	**83**	**82**	**75**	**58**
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production and Metallurgical Coke Production	46	44	34	35	33	31	17
Iron and Steel Production	*46*	*44*	*34*	*35*	*33*	*31*	*17*
Metallurgical Coke Production	+	+	+	+	+	+	+
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
N_2O	**108**	**80**	**69**	**66**	**74**	**60**	**53**
Nitric Acid Production	57	63	53	52	62	53	47
Adipic Acid Production	51	18	16	14	12	7	6
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[a]	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacturing HFCs	+	+	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Aluminum Production	M	M	M	M	M	M	M
Semiconductor Manufacturing PFCs	M	M	M	M	M	M	M
SF_6	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Semiconductor	+	+	+	+	+	+	+

Manufacturing SF_6							
Magnesium Production and Processing	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg
M (Mixture of gases)
Note: Totals may not sum due to independent rounding.
[a] Small amounts of PFC emissions also result from this source.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Procedures

Tier 1 quality assurance and quality control procedures have been performed for all industrial process sources. For industrial process sources of CO_2 and CH_4 emissions, a detailed plan was developed and implemented. This plan was based on the overall U.S. strategy, but was tailored to include specific procedures recommended for these sources. Two types of checks were performed using this plan: (1) general, or Tier 1, procedures that focus on annual procedures and checks to be used when gathering, maintaining, handling, documenting, checking, and archiving the data, supporting documents, and files, and (2) source-category specific, or Tier 2, procedures that focus on procedures and checks of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process sources. Examples of these procedures include checks to ensure that activity data and emission estimates are consistent with historical trends; that, where possible, consistent and reputable data sources are used across sources; that interpolation or extrapolation techniques are consistent across sources; and that common datasets and factors are used where applicable.

The general method employed to estimate emissions for industrial processes, as recommended by the IPCC, involves multiplying production data (or activity data) for each process by an emission factor per unit of production. The uncertainty in the emission estimates is therefore generally a function of a combination of the uncertainties surrounding the production and emission factor variables. Uncertainty of activity data and the associated probability density functions for industrial processes CO_2 sources were estimated based on expert assessment of available qualitative and quantitative information. Uncertainty estimates and probability density functions for the emission factors used to calculate emissions from this source were devised based on IPCC recommendations.

Activity data is obtained through a survey of manufacturers conducted by various organizations (specified within each source); the uncertainty of the activity data is a function of the reliability of plant-level production data and is influenced by the completeness of the survey response. The emission factors used were either derived using calculations that assume precise and efficient chemical reactions, or were based upon empirical data in published references. As a result, uncertainties in the emission coefficients can be attributed to, among other things, inefficiencies in the chemical reactions associated with each production process or to the use of empirically-derived emission factors that are biased; therefore, they may not represent U.S. national averages. Additional assumptions are described within each source.

The uncertainty analysis performed to quantify uncertainties associated with the 2009 inventory estimates from industrial processes continues a multi-year process for developing credible quantitative uncertainty estimates for these source categories using the IPCC Tier 2 approach. As the process continues, the type and the characteristics of the actual probability density functions underlying the input variables are identified and better characterized (resulting in development of more reliable inputs for the model, including accurate characterization of correlation between variables), based primarily on expert judgment. Accordingly, the quantitative uncertainty estimates reported in this section should be considered illustrative and as iterations of ongoing efforts to produce accurate uncertainty estimates. The correlation among data used for estimating emissions for different sources can influence the uncertainty analysis of each individual source. While the uncertainty analysis recognizes very significant connections among sources, a more comprehensive approach that accounts for all linkages will be identified as the uncertainty analysis moves forward.

4.1. Cement Production (IPCC Source Category 2A1)

Cement production is an energy- and raw-material-intensive process that results in the generation of CO_2 from both the energy consumed in making the cement and the chemical process itself.[102] Cement is produced in 36 states and Puerto Rico. CO_2 emitted from the chemical process of cement production is the second largest source of industrial CO_2 emissions in the United States.

During the cement production process, calcium carbonate ($CaCO_3$) is heated in a cement kiln at a temperature of about 1,450°C (2,400°F) to form lime (i.e., calcium oxide or CaO) and CO_2 in a process known as calcination or calcining. A very small amount of carbonates other than $CaCO_3$ and non-carbonates are also present in the raw material; however, for calculation purposes all of the raw material is assumed to be $CaCO_3$. Next, the lime is combined with silica-containing materials to produce clinker (an intermediate product), with the earlier by-product CO_2 being released to the atmosphere. The clinker is then allowed to cool, mixed with a small amount of gypsum and potentially other materials (e.g., slag), and used to make portland cement.[103]

In 2009, U.S. clinker production—including Puerto Rico—totaled 56,116 thousand metric tons (USGS 2011). The resulting CO_2 emissions were estimated to be 29.0 Tg CO_2 Eq. (29,018 Gg) (see Table 4-3).

Table 4-3: CO_2 Emissions from Cement Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	33.3	33,278
2000	40.4	40,405
2005	45.2	45,197
2006	45.8	45,792
2007	44.5	44,538
2008	40.5	40,531
2009	29.0	29,018

Greenhouse gas emissions from cement production grew every year from 1991 through 2006, but have decreased since. Emissions since 1990 have decreased by 13 percent. Emissions decreased significantly between 2008 and 2009, due to the economic recession and associated decrease in demand for construction materials. Cement continues to be a critical component of the construction industry; therefore, the availability of public construction funding, as well as overall economic conditions, have considerable influence on cement production.

Methodology

CO_2 emissions from cement production are created by the chemical reaction of carbon-containing minerals (i.e., calcining limestone) in the cement kiln. While in the kiln, limestone is broken down into CO_2 and lime with the CO_2 released to the atmosphere. The quantity of CO_2 emitted during cement production is directly proportional to the lime content of the clinker. During calcination, each mole of $CaCO_3$ (i.e., limestone) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO_2:

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2$$

CO_2 emissions were estimated by applying an emission factor, in tons of CO_2 released per ton of clinker produced, to the total amount of clinker produced. The emission factor used in this analysis is the product of the average lime fraction for clinker of 65 percent and a constant reflecting the mass of CO_2 released per unit of lime (van Oss 2008). This calculation yields an emission factor of 0.51 tons of CO_2 per ton of clinker produced, which was determined as follows:

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[102] The CO_2 emissions related to the consumption of energy for cement manufacture are accounted for under CO_2 from Fossil Fuel Combustion in the Energy chapter.

[103] Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime) and portland cement (USGS 2011). CO_2 emissions that result from the production of lime used to create masonry cement are included in the Lime Manufacture source category.

$$EF_{\text{Clinker}} = 0.6460\ \text{CaO} \times \left[\frac{44.01\ \text{g/mole}\,\text{CO}_2}{56.08\ \text{g/mole}\,\text{CaO}}\right] = 0.5070\ \text{tons}\ \text{CO}_2/\text{ton clinker}$$

During clinker production, some of the clinker precursor materials remain in the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The emissions attributable to the calcinated portion of the CKD are not accounted for by the clinker emission factor. The IPCC recommends that these additional CKD CO_2 emissions should be estimated as two percent of the CO_2 emissions calculated from clinker production.[104] Total cement production emissions were calculated by adding the emissions from clinker production to the emissions assigned to CKD (IPCC 2006).[105]

The 1990 through 2009 activity data for clinker production (see Table 4-4) were obtained from USGS (US Bureau of Mines 1990 through 1993, USGS 1995 through 2011). The data were compiled by USGS through questionnaires sent to domestic clinker and cement manufacturing plants.

Table 4-4: Clinker Production (Gg)

Year	Clinker
1990	64,355
2000	78,138
2005	87,405
2006	88,555
2007	86,130
2008	78,382
2009	56,116

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that all calcium-containing raw materials are $CaCO_3$, when a small percentage likely consists of other carbonate and non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a representative value (van Oss 2008). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO_2 is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this curing process, these compounds may react with CO_2 in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Because the amount of CO_2 reabsorbed is thought to be minimal, it was not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-5. 2009 CO_2 emissions from cement production were estimated to be between 25.3 and 33.0 Tg CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 13 percent below and 14 percent above the emission estimate of 29.0 Tg CO_2 Eq.

Table 4-5: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Cement Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower	**Upper**	**Lower**	**Upper**

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[104] Default IPCC clinker and CKD emission factors were verified through expert consultation with the Portland Cement Association (PCA 2008) and van Oss (2008).

[105] The two percent CO_2 addition associated with CKD is included in the emission estimate for completeness. The cement emission estimate also includes an assumption that all raw material is limestone ($CaCO_3$) when in fact a small percentage is likely composed of non-carbonate materials. Together these assumptions may result in a small emission overestimate (van Oss 2008).

			Bound	Bound	Bound	Bound
Cement Production	CO_2	29.0	25.3	33.0	-13%	+14%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

Activity data for the time series was revised for the current Inventory. Specifically, clinker production data for 1995 through 2008 (excluding 2001) were revised to reflect published USGS data. In a given Inventory year, advance clinker data is typically used. This data is typically finalized several years later by USGS. The published time series was reviewed to ensure time series consistency. Published data generally differed from advance data by approximately 1,000 metric tons, or 1 percent of the total. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the cement source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from cement production. Beginning in 2010, all U.S. cement production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. cement industry, including also improving emission factors for clinker production and CKD.

4.2. Lime Production (IPCC Source Category 2A2)

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Its major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. For U.S. operations, the term “lime” actually refers to a variety of chemical compounds. These include calcium oxide (CaO), or high-calcium quicklime; calcium hydroxide ($Ca(OH)_2$), or hydrated lime; dolomitic quicklime ([CaO•MgO]); and dolomitic hydrate ([$Ca(OH)_2$•MgO] or [$Ca(OH)_2$•$Mg(OH)_2$]).

Lime production involves three main processes: stone preparation, calcination, and hydration. CO_2 is generated during the calcination stage, when limestone—mostly calcium carbonate ($CaCO_3$)—is roasted at high temperatures in a kiln to produce CaO and CO_2. The CO_2 is given off as a gas and is normally emitted to the atmosphere. Some of the CO_2 generated during the production process, however, is recovered at some facilities for use in sugar refining and precipitated calcium carbonate (PCC) production.[106] In certain additional applications, lime reabsorbs CO_2 during use.

Lime production in the United States—including Puerto Rico—was reported to be 15,781 thousand metric tons in 2009 (USGS 2010). This production resulted in estimated CO_2 emissions of 11.2 Tg CO_2 Eq. (11,223 Gg) (see Table 4-6 and Table 4-7).

Table 4-6: CO_2 Emissions from Lime Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	11.5	11,533
2000	14.1	14,088
2005	14.4	14,379
2006	15.1	15,100
2007	14.6	14,595
2008	14.3	14,330
2009	11.2	11,223

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[106] PCC is obtained from the reaction of CO_2 with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

Table 4-7: Potential, Recovered, and Net CO_2 Emissions from Lime Production (Gg)

Year	Potential	Recovered[*]	Net Emissions
1990	12,004	471	11,533
2000	14,872	784	14,088
2005	15,131	752	14,379
2006	15,825	725	15,100
2007	15,264	669	14,595
2008	14,977	647	14,330
2009	11,913	690	11,223

[*] For sugar refining and PCC production.
Note: Totals may not sum due to rounding

Lime production in 2009 decreased by 21 percent compared to 2008, owing mostly to a significant downturn in major markets such as construction and steel. Because of this significant downturn, overall lime production in 2009 was approximately equal to production in 1990. The contemporary lime market is approximately distributed across five end-use categories as follows: environmental uses, 34 percent; metallurgical uses, 31 percent; chemical and industrial uses, 25 percent; construction uses, 9 percent; and refractory dolomite, 1 percent. In the construction sector, lime is used to improve durability in plaster, stucco, and mortars, as well as to stabilize soils. Consumption for metallurgical uses accounted for 57 percent of the overall decrease in lime consumption (USGS 2010).

Methodology

During the calcination stage of lime production, CO_2 is given off as a gas and normally exits the system with the stack gas. To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their respective emission factors. The emission factor is the product of a constant reflecting the mass of CO_2 released per unit of lime and the average calcium plus magnesium oxide (CaO + MgO) content for lime (95 percent for both types of lime) (IPCC 2006). The emission factors were calculated as follows:

For high-calcium lime:

$$[(44.01 \text{ g/mole } CO_2) \div (56.08 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.7455 \text{ g } CO_2\text{/g lime}$$

For dolomitic lime:

$$[(88.02 \text{ g/mole } CO_2) \div (96.39 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.8675 \text{ g } CO_2\text{/g lime}$$

Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined according to the molecular weight ratios of H_2O to (Ca(OH)2 and [$Ca(OH)_2 \cdot Mg(OH)_2$]) (IPCC 2000). These factors set the chemically combined water content to 24.3 percent for high-calcium hydrated lime, and 27.2 percent for dolomitic hydrated lime.

Lime emission estimates were multiplied by a factor of 1.02 to account for lime kiln dust (LKD), which is produced as a by-product during the production of lime (IPCC 2006).

Lime emission estimates were further adjusted to account for PCC producers and sugar refineries that recover CO_2 emitted by lime production facilities for use as an input into production or refining processes. For CO_2 recovery by sugar refineries, lime consumption estimates from USGS were multiplied by a CO_2 recovery factor to determine the total amount of CO_2 recovered from lime production facilities. According to industry surveys, sugar refineries use captured CO_2 for 100 percent of their CO_2 input (Lutter 2009). CO_2 recovery by PCC producers was determined by multiplying estimates for the percentage CO_2 of production weight for PCC production at lime plants by a CO_2 recovery factor based on the amount of purchased CO_2 by PCC manufacturers (Prillaman 2008 through 2010). As data were only available starting in 2007, CO_2 recovery for the period 1990 through 2006 was extrapolated by determining a ratio of PCC production at lime facilities to lime consumption for PCC (USGS 1992 through 2008).

Lime production data (high-calcium- and dolomitic-quicklime, high-calcium- and dolomitic-hydrated, and dead-burned dolomite) for 1990 through 2009 (see Table 4-8) were obtained from USGS (1992 through 2010). Natural hydraulic lime, which is produced from CaO and hydraulic calcium silicates, is not produced in the United States (USGS 2009). Total lime production was adjusted to account for the water content of hydrated lime by converting hydrate to oxide equivalent based on recommendations from the IPCC, and is presented in Table 4-9 (IPCC 2000). The CaO and CaO•MgO contents of lime were obtained from the IPCC (IPCC 2006). Since data for the individual lime types (high calcium and dolomitic) was not provided prior to 1997, total lime production for 1990 through 1996 was calculated according to the three year distribution from 1997 to 1999.

Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (Gg)

Year	High-Calcium Quicklime	Dolomitic Quicklime	High-Calcium Hydrated	Dolomitic Hydrated	Dead-Burned Dolomite
1990	11,166	2,234	1,781	319	342
2000	14,300	3,000	1,550	421	200
2005	14,100	2,990	2,220	474	200
2006	15,000	2,950	2,370	409	200
2007	14,700	2,700	2,240	352	200
2008	14,900	2,310	2,070	358	200
2009	11,800	1,830	1,690	261	200

Table 4-9: Adjusted Lime Production[a] (Gg)

Year	High-Calcium	Dolomitic
1990	12,514	2,809
2000	15,473	3,506
2005	15,781	3,535
2006	16,794	3,448
2007	16,396	3,156
2008	16,467	2,771
2009	13,079	2,220

[a] Minus water content of hydrated lime

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates can be attributed to slight differences in the chemical composition of these products and recovery rates for sugar refineries and PCC manufacturers located at lime plants. Although the methodology accounts for various formulations of lime, it does not account for the trace impurities found in lime, such as iron oxide, alumina, and silica. Due to differences in the limestone used as a raw material, a rigid specification of lime material is impossible. As a result, few plants produce lime with exactly the same properties.

In addition, a portion of the CO_2 emitted during lime production will actually be reabsorbed when the lime is consumed. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO_2 reacts with the lime to create calcium carbonate (e.g., water softening). CO_2 reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO_2; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. A detailed accounting of lime use in the United States and further research into the associated processes are required to quantify the amount of CO_2 that is reabsorbed.[107]

In some cases, lime is generated from calcium carbonate by-products at pulp mills and water treatment plants.[108]

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[107] Representatives of the National Lime Association estimate that CO_2 reabsorption that occurs from the use of lime may offset as much as a quarter of the CO_2 emissions from calcination (Males 2003).

[108] Some carbide producers may also regenerate lime from their calcium hydroxide by-products, which does not result in

The lime generated by these processes is not included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic C is present from the wood. Kraft mills recover the calcium carbonate "mud" after the causticizing operation and calcine it back into lime—thereby generating CO_2—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO_2 emitted during this process is mostly biogenic in origin, and therefore is not included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands (see Chapter 7).

In the case of water treatment plants, lime is used in the softening process. Some large water treatment plants may recover their waste calcium carbonate and calcine it into quicklime for reuse in the softening process. Further research is necessary to determine the degree to which lime recycling is practiced by water treatment plants in the United States.

Uncertainties also remain surrounding recovery rates used for sugar refining and PCC production. The recovery rate for sugar refineries is based on two sugar beet processing and refining facilities located in California that use 100 percent recovered CO_2 from lime plants (Lutter 2010). This analysis assumes that all sugar refineries located on-site at lime plants also use 100 percent recovered CO_2. The recovery rate for PCC producers located on-site at lime plants is based on the 2009 value for PCC manufactured at commercial lime plants, given by the National Lime Association (Prillaman 2010).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO_2 emissions were estimated to be between 10.4 and 12.3 Tg CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 11.2 Tg CO_2 Eq.

Table 4-10: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lime Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Lime Production	CO_2	11.2	10.4	12.3	-7%	+10%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

No methodological or activity data changes to the time series were made to this source for the current Inventory. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lime source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from lime production. Beginning in 2010, all U.S. lime production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. lime industry, including improving emission factors for various lime types and LKD.

Future improvements to the lime source category will also involve continued research into CO_2 recovery associated with lime use during sugar refining and precipitate calcium carbonate (PCC) production. Currently, two sugar refining facilities in California have been identified to capture CO_2 produced in lime kilns located on the same site as the sugar refinery (Lutter 2010). Data on CO_2 production by these lime facilities is unavailable. Future work will

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emissions of CO_2. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [$CaC_2 + 2H_2O \rightarrow C_2H_2 + Ca(OH)_2$], not calcium carbonate [$CaCO_3$]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [$Ca(OH)_2 + heat \rightarrow CaO + H_2O$] and no CO_2 is released.

include research to determine the number of sugar refineries that employ the carbonation technique, the percentage of these that use captured CO_2 from lime production facilities, and the amount of CO_2 recovered per unit of lime production. Future research will also aim to improve estimates of CO_2 recovered as part of the PCC production process using estimates of PCC production and CO_2 inputs rather than lime consumption by PCC facilities.

4.3. Limestone and Dolomite Use (IPCC Source Category 2A3)

Limestone ($CaCO_3$) and dolomite ($CaCO_3MgCO_3$)[109] are basic raw materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. Limestone is widely distributed throughout the world in deposits of varying sizes and degrees of purity. Large deposits of limestone occur in nearly every state in the United States, and significant quantities are extracted for industrial applications. For some of these applications, limestone is heated sufficiently enough to calcine the material and generate CO_2 as a by-product. Examples of such applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems for utility and industrial plants, or as a raw material in glass manufacturing and magnesium production.

In 2009, approximately 14,928 thousand metric tons of limestone and 3,020 thousand metric tons of dolomite were consumed for these emissive applications. Overall, usage of limestone and dolomite resulted in aggregate CO_2 emissions of 7.6 Tg CO_2 Eq. (7,649 Gg) (see Table 4-11and Table 4-12). Overall, emissions have increased 49 percent from 1990 through 2009.

Table 4-11: CO_2 Emissions from Limestone & Dolomite Use (Tg CO_2 Eq.)

Year	**Flux Stone**	**Glass Making**	**FGD**	**Magnesium Production**	**Other Miscellaneous Uses**	**Total**
1990	2.6	0.2	1.4	0.1	0.8	5.1
2000	2.1	0.4	1.8	0.1	0.7	5.1
2005	2.7	0.4	3.0	0.0	0.7	6.8
2006	4.5	0.7	2.1	0.0	0.7	8.0
2007	2.0	0.3	3.2	0.0	2.2	7.7
2008	1.0	0.4	3.8	0.0	1.1	6.3
2009	1.8	0.1	5.4	0.0	0.4	7.6

Notes: Totals may not sum due to independent rounding. "Other miscellaneous uses" include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

Table 4-12: CO_2 Emissions from Limestone & Dolomite Use (Gg)

Year	**Flux Stone**	**Glass Making**	**FGD**	**Magnesium Production**	**Other Miscellaneous Uses**	**Total**
1990	2,593	217	1,433	64	819	5,127
2000	2,104	371	1,787	73	722	5,056
2005	2,650	425	2,975	0	718	6,768
2006	4,492	747	2,061	0	735	8,035
2007	1,959	333	3,179	0	2,231	7,702
2008	974	387	3,801	0	1,114	6,276
2009	1,785	61	5,406	0	396	7,649

Methodology

CO_2 emissions were calculated by multiplying the quantity of limestone or dolomite consumed by the average C

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[109] Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

content, 12.0 percent for limestone and 13.0 percent for dolomite (based on stoichiometry), and converting this value to CO_2. This methodology was used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining and then converting to CO_2 using a molecular weight ratio. Flux stone used during the production of iron and steel was deducted from the Limestone and Dolomite Use estimate and attributed to the Iron and Steel Production estimate.

Traditionally, the production of magnesium metal was the only other significant use of limestone and dolomite that produced CO_2 emissions. At the start of 2001, there were two magnesium production plants operating in the United States and they used different production methods. One plant produced magnesium metal using a dolomitic process that resulted in the release of CO_2 emissions, while the other plant produced magnesium from magnesium chloride using a CO_2-emissions-free process called electrolytic reduction. However, the plant utilizing the dolomitic process ceased its operations prior to the end of 2001, so beginning in 2002 there were no emissions from this particular sub-use.

Consumption data for 1990 through 2008 of limestone and dolomite used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table 4-13) were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual Report* (1995 through 2010a) and the U.S. Bureau of Mines (1991 & 1993a). Consumption data for 2009 were obtained from personal communication with the USGS crushed stone commodity specialist (Willett 2010). The production capacity data for 1990 through 2009of dolomitic magnesium metal also came from the USGS (1995 through 2010b) and the U.S. Bureau of Mines (1990 through 1993b). The last plant in the United States that used the dolomitic production process for magnesium metal closed in 2001. The USGS does not mention this process in the *Minerals Yearbook: Magnesium*; therefore, it is assumed that this process continues to be non-existent in the United States (USGS 2010b). During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; (2) the average percent of total limestone or dolomite for the withheld end-use in the preceding and succeeding years; or (3) the average fraction of total limestone or dolomite for the end-use over the entire time period.

There is a large quantity of crushed stone reported to the USGS under the category “unspecified uses.” A portion of this consumption is believed to be limestone or dolomite used for emissive end uses. The quantity listed for “unspecified uses” was, therefore, allocated to each reported end use according to each end uses fraction of total consumption in that year.[110]

Table 4-13: Limestone and Dolomite Consumption (Thousand Metric Tons)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Flux Stone	6,737	6,283	7,022	11,030	5,305	3,253	4,623
Limestone	5,804	4,151	3,165	5,208	3,477	1,970	1,631
Dolomite	933	2,132	3,857	5,822	1,827	1,283	2,992
Glass Making	489	843	962	1,693	757	879	139
Limestone	430	843	920	1,629	757	879	139
Dolomite	59	0	43	64	0	0	0
FGD	3,258	4,061	6,761	4,683	7,225	8,639	12,288
Other Miscellaneous Uses	1,835	1,640	1,632	1,671	5,057	2,531	898
Total	**12,319**	**12,826**	**16,377**	**19,078**	**18,344**	**15,302**	**17,948**

Notes: "Other miscellaneous uses" includes chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Zero values for limestone and dolomite consumption for glass making result during years when the USGS reports that no limestone or dolomite are consumed for this use.

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[110] This approach was recommended by USGS.

Uncertainty and Time Series Consistency

The uncertainty levels presented in this section arise in part due to variations in the chemical composition of limestone. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals. The exact specifications for limestone or dolomite used as flux stone vary with the pyrometallurgical process and the kind of ore processed. Similarly, the quality of the limestone used for glass manufacturing will depend on the type of glass being manufactured.

The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the manufacturer and not the end user. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. The uncertainty of the estimates for limestone used in glass making is especially high; however, since glass making accounts for a small percent of consumption, its contribution to the overall emissions estimate is low. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-14. Limestone and Dolomite Use CO_2 emissions were estimated to be between 6.6 and 9.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 19 percent above the emission estimate of 7.6 Tg CO_2 Eq.

Table 4-14: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Limestone and Dolomite Use (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Limestone and Dolomite Use	CO_2	7.6	6.6	9.1	-13%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the limestone and dolomite source category involve research into the availability of limestone and dolomite end-use data, including from EPA’s new Greenhouse Gas Reporting Program. If sufficient data are available, limestone and dolomite used as process materials in source categories included in future inventories (e.g., glass production, other process use of carbonates) may be removed from this section and will be reported under the appropriate source categories. Additionally, future improvements include revisiting the methodology to distribute withheld data across emissive end-uses for all years to improve consistency of calculations.

4.4. Soda Ash Production and Consumption (IPCC Source Category 2A4)

Soda ash (sodium carbonate, Na_2CO_3) is a white crystalline solid that is readily soluble in water and strongly alkaline. Commercial soda ash is used as a raw material in a variety of industrial processes and in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. It is used primarily as an alkali, either in glass manufacturing or simply as a material that reacts with and neutralizes acids or acidic substances. Internationally, two types of soda ash are produced, natural and synthetic. The United States produces only natural soda ash and is second only to China in total soda ash production. Trona is the principal ore from which natural soda ash is made.

Only two states produce natural soda ash: Wyoming and California. Of these two states, only net emissions of CO_2

from Wyoming were calculated due to specifics regarding the production processes employed in the state.[111] During the production process used in Wyoming, trona ore is calcined to produce crude soda ash. CO_2 is generated as a by-product of this reaction, and is eventually emitted into the atmosphere. In addition, CO_2 may also be released when soda ash is consumed.

In 2009, CO_2 emissions from the production of soda ash from trona were approximately 1.7 Tg CO_2 Eq. (1,733 Gg). Soda ash consumption in the United States generated 2.5 Tg CO_2 Eq. (2,532 Gg) in 2009. Total emissions from soda ash production and consumption in 2009 were 4.3 Tg CO_2 Eq. (4,265 Gg) (see Table 4-15 and Table 4-16). Emissions have remained relatively constant with some fluctuations since 1990. These fluctuations were strongly related to the behavior of the export market and the U.S. economy. Emissions from the production of soda ash from trona in 2009 are currently proxied to emissions in 2008, due to lack of available data at time of publication. Emissions in 2009 increased by approximately 4 percent from emissions in 2008, and have also increased overall by 3 percent since 1990.

Table 4-15: CO_2 Emissions from Soda Ash Production and Consumption (Tg CO_2 Eq.)

Year	**Production**	**Consumption**	**Total**
1990	1.4	2.7	4.1
2000	1.5	2.7	4.2
2005	1.7	2.6	4.2
2006	1.6	2.5	4.2
2007	1.7	2.5	4.1
2008	1.7	2.4	4.1
2009	1.7	2.5	4.3

Note: Totals may not sum due to independent rounding.

Table 4-16: CO_2 Emissions from Soda Ash Production and Consumption (Gg)

Year	**Production**	**Consumption**	**Total**
1990	1,431	2,710	4,141
2000	1,529	2,652	4,181
2005	1,655	2,573	4,228
2006	1,626	2,536	4,162
2007	1,675	2,465	4,140
2008	1,733	2,378	4,111
2009	1,733	2,532	4,265

Note: Totals may not sum due to independent rounding.

The United States represents about one-fourth of total world soda ash output. Based on final 2007 reported data, the estimated distribution of soda ash by end-use in 2008 was glass making, 49 percent; chemical production, 30 percent; soap and detergent manufacturing, 8 percent; distributors, 5 percent; flue gas desulfurization, 2 percent; water treatment, 2 percent; pulp and paper production, 2 percent; and miscellaneous, 3 percent (USGS 2009). The same distribution by end-use is currently assumed for 2009, due to lack of available data at time of publication.

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[111] In California, soda ash is manufactured using sodium carbonate-bearing brines instead of trona ore. To extract the sodium carbonate, the complex brines are first treated with CO_2 in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which then precipitates from the brine solution. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO_2 is generated as a by-product, the CO_2 is recovered and recycled for use in the carbonation stage and is not emitted. A third state, Colorado, produced soda ash until the plant was idled in 2004. The lone producer of sodium bicarbonate no longer mines trona in the state. For a brief time, $NaHCO_3$ was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Because the trona is mined in Wyoming, the production numbers given by the USGS included the feedstocks mined in Wyoming and shipped to Colorado. In this way, the sodium bicarbonate production that took place in Colorado was accounted for in the Wyoming numbers.

Although the United States continues to be a major supplier of world soda ash, China, which surpassed the United States in soda ash production in 2003, is the world's leading producer. While Chinese soda ash production appears to be stabilizing, U.S. competition in Asian markets is expected to continue. Despite this competition, U.S. soda ash production is expected to increase by about 0.5 percent annually (USGS 2008).

Methodology

During the production process, trona ore is calcined in a rotary kiln and chemically transformed into a crude soda ash that requires further processing. CO_2 and water are generated as by-products of the calcination process. CO_2 emissions from the calcination of trona can be estimated based on the following chemical reaction:

$$\underset{\text{[trona]}}{2(Na_3(CO_3)(HCO_3)\bullet 2H_2O)} \rightarrow \underset{\text{[soda ash]}}{3Na_2CO_3} + 5H_2O + CO_2$$

Based on this formula, approximately 10.27 metric tons of trona are required to generate one metric ton of CO_2, or an emission factor of 0.097 metric tons CO_2 per metric ton trona (IPCC 2006). Thus, the 17.8 million metric tons of trona mined in 2008 for soda ash production (USGS 2008) resulted in CO_2 emissions of approximately 1.7 Tg CO_2 Eq. (1,733 Gg). The same production and associated emissions estimates are assumed for 2009 due to lack of available data at time of publication.

Once produced, most soda ash is consumed in glass and chemical production, with minor amounts in soap and detergents, pulp and paper, flue gas desulfurization and water treatment. As soda ash is consumed for these purposes, additional CO_2 is usually emitted. In these applications, it is assumed that one mole of C is released for every mole of soda ash used. Thus, approximately 0.113 metric tons of C (or 0.415 metric tons of CO_2) are released for every metric ton of soda ash consumed.

The activity data for trona production and soda ash consumption (see Table 4-17) were taken from USGS (1994 through 2008). Data for soda ash consumption in 2009 was taken from USGS (2010) *Mineral Commodity Summary: Soda Ash*. Due to lack of 2009 trona production data at time of publication, the 2008 estimate is used as a proxy for 2009. Soda ash production and consumption data were collected by the USGS from voluntary surveys of the U.S. soda ash industry.

Table 4-17: Soda Ash Production and Consumption (Gg)

Year	Production*	Consumption
1990	14,700	6,530
2000	15,700	6,390
2005	17,000	6,200
2006	16,700	6,110
2007	17,200	5,940
2008	17,800	5,730
2009	17,800	6,100

* Soda ash produced from trona ore only.

Uncertainty and Time-Series Consistency

Emission estimates from soda ash production have relatively low associated uncertainty levels in that reliable and accurate data sources are available for the emission factor and activity data. The primary source of uncertainty, however, results from the fact that emissions from soda ash consumption are dependent upon the type of processing employed by each end-use. Specific information characterizing the emissions from each end-use is limited. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-18. Soda Ash Production and Consumption CO_2 emissions were estimated to be between 4.0 and 4.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 7 percent above the emission estimate of 4.3 Tg CO_2 Eq.

Table 4-18: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Soda Ash Production and Consumption (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Soda Ash Production and Consumption	CO_2	4.3	4.0	4.6	-7%	+7%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future inventories are anticipated to estimate emissions from glass production and other use of carbonates. These inventories will extract soda ash consumed for glass production and other use of carbonates from the current soda ash consumption emission estimates and include them under those sources.

In addition, future improvements to the soda ash production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from soda ash production. Beginning in 2010, all U.S. soda ash production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. soda ash production industry, including also improving emission factors associated with trona consumption.

4.5. Ammonia Production (IPCC Source Category 2B1) and Urea Consumption

Emissions of CO_2 occur during the production of synthetic ammonia, primarily through the use of natural gas as a feedstock. The natural gas-based, naphtha-based, and petroleum coke-based processes produce CO_2 and hydrogen (H_2), the latter of which is used in the production of ammonia. One N production plant located in Kansas is producing ammonia from petroleum coke feedstock. In some plants the CO_2 produced is captured and used to produce urea. The brine electrolysis process for production of ammonia does not lead to process-based CO_2 emissions.

There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary reforming step converts CH_4 to CO_2, carbon monoxide (CO), and H_2 in the presence of a catalyst. Only 30 to 40 percent of the CH_4 feedstock to the primary reformer is converted to CO and CO_2. The secondary reforming step converts the remaining CH_4 feedstock to CO and CO_2. The CO in the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is converted to CO_2 in the presence of a catalyst, water, and air in the shift conversion step. CO_2 is removed from the process gas by the shift conversion process, and the hydrogen gas is combined with the nitrogen (N_2) gas in the process gas during the ammonia synthesis step to produce ammonia. The CO_2 is included in a waste gas stream with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO_2 is released.

The conversion process for conventional steam reforming of CH_4, including primary and secondary reforming and the shift conversion processes, is approximately as follows:

$$0.88\ CH_4 + 1.26\ \text{Air} + 1.24\ H_2O \xrightarrow{\text{(catalyst)}} 0.88\ CO_2 + N_2 + 3\ H_2$$

$$N_2 + 3\ H_2 \rightarrow 2\ NH_3$$

To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO_2 and H_2. These gases are separated, and the H_2 is used as a feedstock to the ammonia production process, where it is reacted with N_2 to form ammonia.

Not all of the CO_2 produced in the production of ammonia is emitted directly to the atmosphere. Both ammonia and CO_2 are used as raw materials in the production of urea [$CO(NH_2)_2$], which is another type of nitrogenous fertilizer that contains C as well as N. The chemical reaction that produces urea is:

$$2\ NH_3 + CO_2 \rightarrow\ NH_2COONH_4 \rightarrow CO(NH_2)_2 + H_2O$$

Urea is consumed for a variety of uses, including as a nitrogenous fertilizer, in urea-formaldehyde resins, and as a deicing agent (TIG 2002). The C in the consumed urea is assumed to be released into the environment as CO_2 during use. Therefore, the CO_2 produced by ammonia production that is subsequently used in the production of urea is still emitted during urea consumption. The majority of CO_2 emissions associated with urea consumption are those that result from its use as a fertilizer. These emissions are accounted for in the Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. CO_2 emissions associated with other uses of urea are accounted for in this chapter. Net emissions of CO_2 from ammonia production in 2009 were 11.8 Tg CO_2 Eq. (11,797 Gg), and are summarized in Table 4-19 and Table 4-20. Emissions of CO_2 from urea consumed for non-fertilizer purposes in 2009 totaled 3.9 Tg CO_2 Eq. (3,942 Gg), and are summarized in Table 4-19 and Table 4-20. The decrease in ammonia production in recent years is due to several factors, including market fluctuations and high natural gas prices. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, domestic producers are competing with imports from countries with lower gas prices. If natural gas prices remain high, it is likely that domestically produced ammonia will continue to decrease with increasing ammonia imports (EEA 2004).

Table 4-19: CO_2 Emissions from Ammonia Production and Urea Consumption (Tg CO_2 Eq.)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13.0	12.2	9.2	8.8	9.1	7.9	7.9
Urea Consumption[a]	3.8	4.2	3.7	3.5	5.0	4.1	3.9
Total	**16.8**	**16.4**	**12.8**	**12.3**	**14.0**	**11.9**	**11.8**

Note: Totals may not sum due to independent rounding.

[a] Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Table 4-20: CO_2 Emissions from Ammonia Production and Urea Consumption (Gg)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13,047	12,172	9,196	8,781	9,074	7,883	7,855
Urea Consumption[a]	3,784	4,231	3,653	3,519	4,963	4,066	3,942
Total	**16,831**	**16,402**	**12,849**	**12,300**	**14,038**	**11,949**	**11,797**

[a] Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Methodology

The calculation methodology for non-combustion CO_2 emissions from production of nitrogenous fertilizers from natural gas feedstock is based on a CO_2 emission factor published by the European Fertilizer Manufacturers Association (EFMA). The selected EFMA factor is based on ammonia production technologies that are similar to those employed in the United States. The CO_2 emission factor (1.2 metric tons CO_2/metric ton NH_3) is applied to the percent of total annual domestic ammonia production from natural gas feedstock. Emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Emissions of CO_2 from ammonia production are then adjusted to account for the use of some of the CO_2 produced from ammonia production as a raw material in the production of urea. For each ton of urea produced, 8.8 of every 12 tons of CO_2 are consumed and 6.8 of every 12 tons of ammonia are consumed (IPCC 2006, EFMA 2000). The CO_2 emissions reported for ammonia production are therefore reduced by a factor of 0.73 multiplied by total annual domestic urea production. Total CO_2 emissions resulting from nitrogenous fertilizer production do not change as a result of this calculation, but some of the CO_2 emissions are attributed to ammonia production and some of the CO_2 emissions are attributed to urea consumption. Those CO_2 emissions that result from the use of urea as a fertilizer are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

The total amount of urea consumed for non-agricultural purposes is estimated by deducting the quantity of urea fertilizer applied to agricultural lands, which is obtained directly from the Land Use, Land-Use Change, and Forestry Chapter and is reported in Table 4-21, from total U.S. production. Total urea production is estimated based on the amount of urea produced plus the sum of net urea imports and exports. CO_2 emissions associated with urea that is used for non-fertilizer purposes are estimated using a factor of 0.73 tons of CO_2 per ton of urea consumed.

All ammonia production and subsequent urea production are assumed to be from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of ammonia production from petroleum coke feedstock at one plant located in Kansas. The CO_2 emission factor for production of ammonia from petroleum coke is based on plant specific data, wherein all C contained in the petroleum coke feedstock that is not used for urea production is assumed to be emitted to the atmosphere as CO_2 (Bark 2004). Ammonia and urea are assumed to be manufactured in the same manufacturing complex, as both the raw materials needed for urea production are produced by the ammonia production process. The CO_2 emission factor (3.57 metric tons CO_2/metric ton NH_3) is applied to the percent of total annual domestic ammonia production from petroleum coke feedstock.

The emission factor of 1.2 metric ton CO_2/metric ton NH_3 for production of ammonia from natural gas feedstock was taken from the EFMA Best Available Techniques publication, Production of Ammonia (EFMA 1995). The EFMA reported an emission factor range of 1.15 to 1.30 metric ton CO_2/metric ton NH_3, with 1.2 metric ton CO_2/metric ton NH_3 as a typical value. Technologies (e.g., catalytic reforming process) associated with this factor are found to closely resemble those employed in the U.S. for use of natural gas as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH_4 feedstock to the catalytic reforming process is ultimately converted to CO_2. The emission factor of 3.57 metric ton CO_2/metric ton NH_3 for production of ammonia from petroleum coke feedstock was developed from plant-specific ammonia production data and petroleum coke feedstock utilization data for the ammonia plant located in Kansas (Bark 2004). As noted earlier, emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Ammonia production data (see Table 4-21) was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010) and the Census Bureau of the U.S. Department of Commerce (U.S. Census Bureau 1991 through 1994, 1998 through 2010) as reported in Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports. Urea-ammonia nitrate production was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010). Urea production data for 1990 through 2008 were obtained from the Minerals Yearbook: Nitrogen (USGS 1994 through 2009). Urea production data for 2009 was obtained from the U.S. Bureau of the Census (2010). Import data for urea were obtained from the U.S. Census Bureau Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports for 1997 through 2009 (U.S. Census Bureau 1998 through 2010), The Fertilizer Institute (TFI 2002) for 1993 through 1996, and the United States International Trade Commission Interactive Tariff and Trade DataWeb (U.S. ITC 2002) for 1990 through 1992 (see Table 4-21). Urea export data for 1990 through 2009 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2010).

Table 4-21: Ammonia Production, Urea Production, Urea Net Imports, and Urea Exports (Gg)

Year	Ammonia Production	Urea Production	Urea Applied as Fertilizer	Urea Imports	Urea Exports
1990	15,425	7,450	3,296	1,860	854
2000	14,342	6,910	4,382	3,904	663
2005	10,143	5,270	4,779	5,026	536
2006	9,962	5,410	4,985	5,029	656
2007	10,393	5,590	5,097	6,546	271
2008	9,570	5,240	4,925	5,459	230
2009	9,372	5,084	4,295	5,505	289

Uncertainty and Time-Series Consistency

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with natural gas feedstock consumption data for the U.S. ammonia industry as a whole, the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. It is also assumed that ammonia and urea are produced at collocated plants from the same natural gas raw material.

Such recovery may or may not affect the overall estimate of CO_2 emissions depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether byproduct CO_2 is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

Additional uncertainty is associated with the estimate of urea consumed for non-fertilizer purposes. Emissions associated with this consumption are reported in this source category, while those associated with consumption as fertilizer are reported in Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. The amount of urea used for non-fertilizer purposes is estimated based on estimates of urea production, net urea imports, and the amount of urea used as fertilizer. There is uncertainty associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-22. Ammonia Production and Urea Consumption CO_2 emissions were estimated to be between 10.9 and 12.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 8 percent above the emission estimate of 11.8 Tg CO_2 Eq.

Table 4-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ammonia Production and Urea Consumption (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Ammonia Production and Urea Consumption	CO_2	11.8	10.9	12.7	-7%	+8%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

The uncertainty range (-7 percent/+8 percent) has decreased by 7 percent compared to the uncertainty range in the previous Inventory (±11 percent), due to two stoichiometric variables being removed from the uncertainty analysis.

Planned Improvements

Future improvements to the ammonia production and urea consumption category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ammonia production. Beginning in 2010, all U.S. ammonia production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. ammonia production. Specifically, the planned improvements include assessing data to update the emission factors to include both fuel and feedstock CO_2 emissions and incorporate CO_2 capture and storage. Methodologies will also be updated if additional ammonia-production plants are found to use hydrocarbons other than natural gas for ammonia production. Additional efforts will be made to find consistent data sources for urea consumption and to report emissions from this consumption appropriately as defined.

4.6. *Nitric Acid Production (IPCC Source Category 2B2)*

Nitric acid (HNO_3) is an inorganic compound used primarily to make synthetic commercial fertilizers. It is also a major component in the production of adipic acid—a feedstock for nylon—and explosives. Virtually all of the nitric acid produced in the United States is manufactured by the catalytic oxidation of ammonia (EPA 1997). During this reaction, N_2O is formed as a by-product and is released from reactor vents into the atmosphere.

Currently, the nitric acid industry controls for emissions of NO and NO_2 (i.e., NO_x). As such, the industry in the US uses a combination of non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR) technologies. In the process of destroying NO_x, NSCR systems are also very effective at destroying N_2O. However, NSCR units are generally not preferred in modern plants because of high energy costs and associated high gas temperatures. NSCRs were widely installed in nitric plants built between 1971 and 1977. Approximately 25 percent of nitric acid plants use NSCR and they represent 15.3 percent of estimated national production (EPA 2010a). The remaining 84.7 percent of production occurs using SCR or extended absorption, neither of which is known to reduce N_2O emissions.

N_2O emissions from this source were estimated to be 14.6 Tg CO_2 Eq. (47 Gg) in 2009 (see Table 4-23). Emissions from nitric acid production have decreased by 18 percent since 1990, with the trend in the time series closely tracking the changes in production. Emissions decreased 11.4 percent between 2008 and 2009. Emissions have decreased by 30.8 percent since 1997, the highest year of production in the time series.

Table 4-23: N_2O Emissions from Nitric Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	17.7	57
2000	19.4	63
2005	16.5	53
2006	16.2	52
2007	19.2	62
2008	16.4	53
2009	14.6	47

Methodology

N_2O emissions were calculated by multiplying nitric acid production by the amount of N_2O emitted per unit of nitric acid produced. The emission factor was determined as a weighted average of two known emission factors: 2 kg N_2O/metric ton HNO_3 produced at plants using non-selective catalytic reduction (NSCR) systems and 9 kg N_2O/metric ton HNO_3 produced at plants not equipped with NSCR (IPCC 2006). In the process of destroying NO_x, NSCR systems destroy 80 to 90 percent of the N_2O, which is accounted for in the emission factor of 2 kg N_2O/metric ton HNO_3. Approximately 25 percent of HNO_3 plants in the United States are equipped with NSCR representing 15.3 percent of estimated national production (EPA 2010a). Hence, the emission factor is equal to $(9 \times 0.847) + (2 \times 0.153) = 7.9$ kg N_2O per metric ton HNO_3.

Nitric acid production data for 1990 through 2002 were obtained from the U.S. Census Bureau, Current Industrial Reports (2006). Production data for 2003 were obtained from the U.S. Census Bureau, Current Industrial Reports (2008). Production data for 2004 through 2009 were obtained from the U.S. Census Bureau, Current Industrial Reports (2010) (see Table 4-24).

Table 4-24: Nitric Acid Production (Gg)

Year	Gg
1990	7,195
2000	7,900
2005	6,711
2006	6,572
2007	7,827
2008	6,686
2009	5,924

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emissions estimate from nitric acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology.

Uncertainty associated with the parameters used to estimate N_2O emissions included that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series, and the emission factors applied to each abatement technology type.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-25. N_2O emissions from nitric acid production were estimated to be between 8.8 and 20.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emissions estimate of 14.6 Tg CO_2 Eq.

Table 4-25: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from Nitric Acid Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Nitric Acid Production	N_2O	14.6	8.8	20.7	-40%	+42%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the nitric acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from nitric acid production. Beginning in 2010, all U.S. nitric acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. nitric acid production. Specifically, the planned improvements include assessing data to update the N_2O emission factors, abatement utilization and destruction factors, and the current share of nitric acid production attributable to various abatement technologies.

Recalculations Discussion

Historical estimates for N_2O emissions from nitric acid production have been revised relative to the previous Inventory based on updated information from EPA (2010) on abatement technologies in use and based on revised production data published by the U.S. Census Bureau (2010). The previous Inventory assumed that approximately 17 percent of facilities accounting for less than 8 percent of national production were equipped with NSCR systems (EPA 2010b). The current Inventory assumes that approximately 25 percent of facilities, accounting for roughly 15 percent of national production, were equipped with NSCR systems (EPA 2010a). This change resulted in a decrease in the weighted average emission factor of 0.6 kg N_2O/metric ton HNO_3 (6.3 percent). Additionally, national nitric acid production values for 1991, 1993-1995, 1997-1999, 2002, and 2008 have been updated relative to the previous Inventory (US Census Bureau 2009, 2010). Revised production in 2008 contributed to an overall decrease in emissions of 2.6 Tg CO_2 Eq. (13.6 percent) in that year; revised production in the other historical years had a negligible impact on emissions. Overall, changes relative to the previous Inventory resulted in an average annual decrease in emissions of 1.3 Tg CO_2 Eq. (6.7 percent) for the period 1990 through 2008.

4.7. Adipic Acid Production (IPCC Source Category 2B3)

Adipic acid production is an anthropogenic source of N_2O emissions. Worldwide, few adipic acid plants exist. The United States and Europe are the major producers. In 2009, the United States had two companies with a total of three adipic acid processes, two of which were operational (CW 2007; Desai 2010; VA DEQ 2009). The United States accounts for the largest share of global adipic acid production capacity (30 percent), followed by the European Union (29 percent) and China (22 percent) (SEI 2010). Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters.

84 percent of all adipic acid produced in the United States is used in the production of nylon 6,6; nine percent is used in the production of polyester polyols; four percent is used in the production of plasticizers; and the remaining four percent is accounted for by other uses, including unsaturated polyester resins and food applications (ICIS 2007). Food grade adipic acid is used to provide some foods with a "tangy" flavor (Thiemens and Trogler 1991).

Adipic acid is produced through a two-stage process during which N_2O is generated in the second stage. The first stage of manufacturing usually involves the oxidation of cyclohexane to form a cyclohexanone/cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid. N_2O is generated as a by-product of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. In 1990, two of the three major adipic acid-producing plants had N_2O abatement technologies in place and, as of 1998, the three major adipic acid production facilities had control systems in place (Reimer et al. 1999). One small plant, which last operated in April 2006 and represented approximately two percent of production, did not control for N_2O (VA DEQ 2009; ICIS 2007; VA DEQ 2006).

N_2O emissions from adipic acid production were estimated to be 1.9 Tg CO_2 Eq. (6 Gg) in 2009 (see Table 4-26). National adipic acid production has increased by approximately 11 percent over the period of 1990 through 2009, to roughly 820,000 metric tons. Over the same period, emissions have been reduced by 88 percent due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. In April 2006, the smallest of the four facilities ceased production of adipic acid (VA DEQ 2009); furthermore, one of the major adipic acid production facilities was not operational in 2009 (Desai 2010).

Table 4-26: N_2O Emissions from Adipic Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	15.8	51
2000	5.5	18
2005	5.0	16
2006	4.3	14
2007	3.7	12
2008	2.0	7
2009	1.9	6

Methodology

Due to confidential business information, plant names are not provided in this section. The four adipic acid-producing plants will henceforth be referred to as Plants 1 through 4.

For Plants 1 and 2, 1990 to 2009 emission estimates were obtained directly from the plant engineer and account for reductions due to control systems in place at these plants during the time series (Desai 2010). These estimates were based on continuous emissions monitoring equipment installed at the two facilities. In 2009, no Adipic acid production occurred at Plant 1. For Plants 3 and 4, N_2O emissions were calculated by multiplying adipic acid production by an emission factor (i.e., N_2O emitted per unit of adipic acid produced) and adjusting for the percentage of N_2O released as a result of plant-specific emission controls. On the basis of experiments, the overall reaction stoichiometry for N_2O production in the preparation of adipic acid was estimated at approximately 0.3 metric tons of N_2O per metric ton of product (IPCC 2006). Emissions are estimated using the following equation:

$$N_2O \text{ emissions} = (\text{production of adipic acid [metric tons \{MT\} of adipic acid]}) \times (0.3 \text{ MT } N_2O / \text{MT adipic acid}) \times (1 - [N_2O \text{ destruction factor} \times \text{abatement system utility factor}])$$

The "N_2O destruction factor" represents the percentage of N_2O emissions that are destroyed by the installed abatement technology. The "abatement system utility factor" represents the percentage of time that the abatement equipment operates during the annual production period. Overall, in the United States, two of the plants employ catalytic destruction (Plants 1 and 2), one plant employs thermal destruction (Plant 3), and the smallest plant used no N_2O abatement equipment (Plant 4). For Plant 3, which uses thermal destruction and for which no reported plant-specific emissions are available, the N_2O abatement system destruction factor is assumed to be 98.5 percent, and the abatement system utility factor is assumed to be 97 percent (IPCC 2006).

From 1990 to 2003, plant-specific production data were estimated for Plant 3 where direct emission measurements were not available. In order to calculate plant-specific production for this plant, national adipic acid production was allocated to the plant level using the ratio of known plant capacity to total national capacity for all U.S. plants. The estimated plant production for this plant was then used for calculating emissions as described above. For 2004 and 2006, actual plant production data were obtained and used for emission calculations (CW 2007; CW 2005). For 2005, interpolated national production was used for calculating emissions. Updated production data were not available for Plant 3 for 2007 through 2009; therefore, production values for 2007 through 2009 were proxied using 2006 data.

For Plant 4, which last operated in April 2006 (VA DEQ 2009), plant-specific production data were obtained across the time series from 1990 through 2008 (VA DEQ 2010). Since the plant has not operated since 2006, production in 2009 is assumed to be equal to the 2008 estimate, which was zero. The plant-specific production data were then used for calculating emissions as described above.

National adipic acid production data (see Table 4-27) from 1990 through 2009 were obtained from the American Chemistry Council (ACC 2010).

Plant capacities for 1990 through 1994 were obtained from Chemical and Engineering News, "Facts and Figures" and "Production of Top 50 Chemicals" (C&EN 1992 through 1995). Plant capacities for 1995 and 1996 were kept the same as 1994 data. The 1997 plant capacities were taken from Chemical Market Reporter "Chemical Profile: Adipic Acid" (CMR 1998). The 1998 plant capacities for all four plants and 1999 plant capacities for three of the plants were obtained from Chemical Week, Product Focus: Adipic Acid/Adiponitrile (CW 1999). Plant capacities for 2000 for three of the plants were updated using Chemical Market Reporter, "Chemical Profile: Adipic Acid" (CMR 2001). For 2001 through 2005, the plant capacities for three plants were kept the same as the year 2000 capacities. Plant capacity for 1999 to 2005 for the one remaining plant was kept the same as 1998. For 2004 to 2009, although some plant capacity data are available (CW 1999, CMR 2001, ICIS 2007), they are not used to calculate plant-specific production for these years because plant-specific production data for 2004 and 2006 are also available and are used in our calculations instead (CW 2005, CW 2007).

Table 4-27: Adipic Acid Production (Gg)

Year	Gg
1990	735
2000	925
2005	903
2006	964
2007	930
2008	869
2009	819

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emission estimate from adipic acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N_2O emissions included that of company specific production data, emission factors for abated and unabated emissions, and company-specific historical emission estimates.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-28. N_2O emissions from adipic acid production were estimated to be between 1.2 and 2.8 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emission estimate of 1.9 Tg CO_2 Eq.

Table 4-28: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from Adipic Acid Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)	(%)

			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Adipic Acid Production	N_2O	1.9	1.2	2.8	-40%	+42%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations

The current Inventory uses national production data from the ACC (2010) across the full time series. Previous Inventories relied upon a variety of sources and linear interpolation for missing intervening years in the national production time series. This change resulted in an average annual decrease in the national production estimate of approximately 2 percent for the period 1990 through 2008 relative to the previous Inventory. Emissions decreased by less than 0.1 percent over the same time period relative to the previous Inventory.

Planned Improvements

Future improvements to the adipic acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from adipic acid production. Beginning in 2010, all U.S. adipic acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. adipic acid production. Specifically, the planned improvements include assessing data to update the N_2O emission factors and update abatement utility and destruction factors based on actual performance of the latest catalytic and thermal abatement equipment at plants with continuous process and emission monitoring equipment.

4.8. Silicon Carbide Production (IPCC Source Category 2B4) and Consumption

CO_2 and CH_4 are emitted from the production[112] of silicon carbide (SiC), a material used as an industrial abrasive. To make SiC, quartz (SiO_2) is reacted with C in the form of petroleum coke. A portion (about 35 percent) of the C contained in the petroleum coke is retained in the SiC. The remaining C is emitted as CO_2, CH_4, or CO.

CO_2 is also emitted from the consumption of SiC for metallurgical and other non-abrasive applications. The USGS reports that a portion (approximately 50 percent) of SiC is used in metallurgical and other non-abrasive applications, primarily in iron and steel production (USGS 2006).

CO_2 from SiC production and consumption in 2009 were 0.1 Tg CO_2 Eq. (145 Gg) (USGS 2009). Approximately 63 percent of these emissions resulted from SiC production while the remainder results from SiC consumption. CH_4 emissions from SiC production in 2009 were 0.01 Tg CO_2 Eq. CH_4 (0.4 Gg) (see Table 4-29 and Table 4-30).

Table 4-29: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH_4	+	+	+	+	+	+	+
Total	**0.4**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 4-30: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

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[112] Silicon carbide is produced for both abrasive and metallurgical applications in the United States. Production for metallurgical applications is not available and therefore both CH_4 and CO_2 estimates are based solely upon production estimates of silicon carbide for abrasive applications.

CO_2	375		248		219	207	196	175	145
CH_4	1		1		+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 and CH_4 from the production of SiC were calculated by multiplying annual SiC production by the emission factors (2.62 metric tons CO_2/metric ton SiC for CO_2 and 11.6 kg CH_4/metric ton SiC for CH_4) provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Emissions of CO_2 from silicon carbide consumption were calculated by multiplying the annual SiC consumption (production plus net imports) by the percent used in metallurgical and other non-abrasive uses (50 percent) (USGS 2009). The total SiC consumed in metallurgical and other non-abrasive uses was multiplied by the C content of SiC (31.5 percent), which was determined according to the molecular weight ratio of SiC.

Production data for 1990 through 2008 were obtained from the Minerals Yearbook: Manufactured Abrasives (USGS 1991a through 2005a, 2007, and 2009). Production data for 2009 was taken from the Minerals Commodity Summary: Abrasives (Manufactured) (USGS 2010). Silicon carbide consumption by major end use was obtained from the Minerals Yearbook: Silicon (USGS 1991b through 2005b) (see Table 4-31) for years 1990 through 2004 and from the USGS Minerals Commodity Specialist for 2005 and 2006 (Corathers 2006, 2007). Silicon carbide consumption by major end use data for 2009 is proxied using 2008 data due to unavailability of data at time of publication. Net imports for the entire time series were obtained from the U.S. Census Bureau (2005 through 2010).

Table 4-31: Production and Consumption of Silicon Carbide (Metric Tons)

Year	Production	Consumption
1990	105,000	172,465
2000	45,000	225,070
2005	35,000	220,149
2006	35,000	199,937
2007	35,000	179,741
2008	35,000	144,928
2009	35,000	92,280

Uncertainty and Time-Series Consistency

There is uncertainty associated with the emission factors used because they are based on stoichiometry as opposed to monitoring of actual SiC production plants. An alternative would be to calculate emissions based on the quantity of petroleum coke used during the production process rather than on the amount of silicon carbide produced. However, these data were not available. For CH_4, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also some uncertainty associated with production, net imports, and consumption data as well as the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-32. Silicon carbide production and consumption CO_2 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.2 Tg CO_2 Eq. at the 95 percent confidence level. Silicon carbide production CH_4 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.01 Tg CO_2 Eq. at the 95 percent confidence level.

Table 4-32: Tier 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Silicon Carbide Production and Consumption (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Silicon Carbide Production	CO_2	0.2	0.13	0.16	-9%	+9%

and Consumption						
Silicon Carbide Production	CH_4	+	+	+	-9%	+9%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 Tg CO_2 Eq. or 0.5 Gg.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the silicon carbide production source category include evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from silicon carbide production. Beginning in 2010, all U.S. silicon carbide production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. silicon carbide production industry. In addition, improvements will involve continued research to determine if calcium carbide production and consumption data are available for the United States. If these data are available, calcium carbide emission estimates will be included in this source category. Additionally, as future improvement to the silicon carbide uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify the uncertainty range associated with silicon carbide emissive utilization.

4.9. Petrochemical Production (IPCC Source Category 2B5)

The production of some petrochemicals results in the release of small amounts of CH_4 and CO_2 emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. CH_4 emissions are presented here from the production of carbon black, ethylene, ethylene dichloride, and methanol, while CO_2 emissions are presented here for only carbon black production. The CO_2 emissions from petrochemical processes other than carbon black are currently included in the Carbon Stored in Products from Non-Energy Uses of Fossil Fuels Section of the Energy chapter. The CO_2 from carbon black production is included here to allow for the direct reporting of CO_2 emissions from the process and direct accounting of the feedstocks used in the process.

Carbon black is an intense black powder generated by the incomplete combustion of an aromatic petroleum or coal-based feedstock. Most carbon black produced in the United States is added to rubber to impart strength and abrasion resistance, and the tire industry is by far the largest consumer. Ethylene is consumed in the production processes of the plastics industry including polymers such as high, low, and linear low density polyethylene (HDPE, LDPE, LLDPE), polyvinyl chloride (PVC), ethylene dichloride, ethylene oxide, and ethylbenzene. Ethylene dichloride is one of the first manufactured chlorinated hydrocarbons with reported production as early as 1795. In addition to being an important intermediate in the synthesis of chlorinated hydrocarbons, ethylene dichloride is used as an industrial solvent and as a fuel additive. Methanol is an alternative transportation fuel as well as a principle ingredient in windshield wiper fluid, paints, solvents, refrigerants, and disinfectants. In addition, methanol-based acetic acid is used in making PET plastics and polyester fibers.

Emissions of CO_2 and CH_4 from petrochemical production in 2009 were 2.7 Tg CO_2 Eq. (2,735 Gg) and 0.8 Tg CO_2 Eq. (40 Gg), respectively (see Table 4-33 and Table 4-34), totaling 3.6 Tg CO_2 Eq. There has been an overall decrease in CO_2 emissions from carbon black production of 17 percent since 1990. CH_4 emissions from petrochemical production decreased by approximately two percent since 1990.

Table 4-33: CO_2 and CH_4 Emissions from Petrochemical Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	3.3	4.5	4.2	3.8	3.9	3.4	2.7
CH_4	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Total	**4.2**	**5.7**	**5.3**	**4.8**	**4.9**	**4.4**	**3.6**

Note: Totals may not sum due to independent rounding.

Table 4-34: CO_2 and CH_4 Emissions from Petrochemical Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

CO_2	3,311		4,479		4,181	3,837	3,931	3,449	2,735
CH_4	41		59		51	48	48	43	40

Methodology

Emissions of CH_4 were calculated by multiplying annual estimates of chemical production by the appropriate emission factor, as follows: 11 kg CH_4/metric ton carbon black, 1 kg CH_4/metric ton ethylene, 0.4 kg CH_4/metric ton ethylene dichloride,[113] and 2 kg CH_4/metric ton methanol. Although the production of other chemicals may also result in CH_4 emissions, insufficient data were available to estimate their emissions.

Emission factors were taken from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). Annual production data (see Table 4-35) were obtained from the American Chemistry Council's Guide to the Business of Chemistry (ACC 2002, 2003, 2005 through 2010) and the International Carbon Black Association (Johnson 2003, 2005 through 2010). Note that 2009 production data for Methanol was not available at time of publication, as such, 2008 methanol production is used as a proxy for 2009.

Table 4-35: Production of Selected Petrochemicals (Thousand Metric Tons)

Chemical	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Carbon Black	1,307		1,769		1,651	1,515	1,552	1,362	1,080
Ethylene	16,541		24,970		23,954	25,000	25,392	22,539	22,596
Ethylene Dichloride	6,282		9,866		11,260	9,736	9,566	8,981	8,131
Methanol	3,785		5,221		2,336	1,123	1,068	1,136	1,136

Almost all carbon black in the United States is produced from petroleum-based or coal-based feedstocks using the "furnace black" process (European IPPC Bureau 2004). The furnace black process is a partial combustion process in which a portion of the carbon black feedstock is combusted to provide energy to the process. Carbon black is also produced in the United States by the thermal cracking of acetylene-containing feedstocks ("acetylene black process") and by the thermal cracking of other hydrocarbons ("thermal black process"). One U.S carbon black plant produces carbon black using the thermal black process, and one U.S. carbon black plant produces carbon black using the acetylene black process (The Innovation Group 2004).

The furnace black process produces carbon black from "carbon black feedstock" (also referred to as "carbon black oil"), which is a heavy aromatic oil that may be derived as a byproduct of either the petroleum refining process or the metallurgical (coal) coke production process. For the production of both petroleum-derived and coal-derived carbon black, the "primary feedstock" (i.e., carbon black feedstock) is injected into a furnace that is heated by a "secondary feedstock" (generally natural gas). Both the natural gas secondary feedstock and a portion of the carbon black feedstock are oxidized to provide heat to the production process and pyrolyze the remaining Carbon black feedstock to carbon black. The "tail gas" from the furnace black process contains CO_2, carbon monoxide, sulfur compounds, CH_4, and non-CH_4 volatile organic compounds. A portion of the tail gas is generally burned for energy recovery to heat the downstream carbon black product dryers. The remaining tail gas may also be burned for energy recovery, flared, or vented uncontrolled to the atmosphere.

The calculation of the C lost during the production process is the basis for determining the amount of CO_2 released during the process. The C content of national carbon black production is subtracted from the total amount of C contained in primary and secondary carbon black feedstock to find the amount of C lost during the production process. It is assumed that the C lost in this process is emitted to the atmosphere as either CH_4 or CO_2. The C content of the CH_4 emissions, estimated as described above, is subtracted from the total C lost in the process to calculate the amount of C emitted as CO_2. The total amount of primary and secondary carbon black feedstock consumed in the process (see Table 4-36) is estimated using a primary feedstock consumption factor and a secondary feedstock consumption factor estimated from U.S. Census Bureau (1999, 2004, and 2007) data. The average carbon black feedstock consumption factor for U.S. carbon black production is 1.69 metric tons of carbon black feedstock consumed per metric ton of carbon black produced. The average natural gas consumption factor for

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[113] The emission factor obtained from IPCC/UNEP/OECD/IEA (1997), page 2.23 is assumed to have a misprint; the chemical identified should be ethylene dichloride ($C_2H_4Cl_2$) rather than dichloroethylene ($C_2H_2Cl_2$).

U.S. carbon black production is 321 normal cubic meters of natural gas consumed per metric ton of carbon black produced. The amount of C contained in the primary and secondary feedstocks is calculated by applying the respective C contents of the feedstocks to the respective levels of feedstock consumption (EIA 2003, 2004).

Table 4-36: Carbon Black Feedstock (Primary Feedstock) and Natural Gas Feedstock (Secondary Feedstock) Consumption (Thousand Metric Tons)

Activity	1990	2000	2005	2006	2007	2008	2009
Primary Feedstock	2,213	2,993	2,794	2,564	2,627	2,305	1,828
Secondary Feedstock	284	384	359	329	337	296	235

For the purposes of emissions estimation, 100 percent of the primary carbon black feedstock is assumed to be derived from petroleum refining byproducts. Carbon black feedstock derived from metallurgical (coal) coke production (e.g., creosote oil) is also used for carbon black production; however, no data are available concerning the annual consumption of coal-derived carbon black feedstock. Carbon black feedstock derived from petroleum refining byproducts is assumed to be 89 percent elemental C (Srivastava et al. 1999). It is assumed that 100 percent of the tail gas produced from the carbon black production process is combusted and that none of the tail gas is vented to the atmosphere uncontrolled. The furnace black process is assumed to be the only process used for the production of carbon black because of the lack of data concerning the relatively small amount of carbon black produced using the acetylene black and thermal black processes. The carbon black produced from the furnace black process is assumed to be 97 percent elemental C (Othmer et al. 1992).

Uncertainty and Time-Series Consistency

The CH_4 emission factors used for petrochemical production are based on a limited number of studies. Using plant-specific factors instead of average factors could increase the accuracy of the emission estimates; however, such data were not available. There may also be other significant sources of CH_4 arising from petrochemical production activities that have not been included in these estimates.

The results of the quantitative uncertainty analysis for the CO_2 emissions from carbon black production calculation are based on feedstock consumption, import and export data, and carbon black production data. The composition of carbon black feedstock varies depending upon the specific refinery production process, and therefore the assumption that carbon black feedstock is 89 percent C gives rise to uncertainty. Also, no data are available concerning the consumption of coal-derived carbon black feedstock, so CO_2 emissions from the utilization of coal-based feedstock are not included in the emission estimate. In addition, other data sources indicate that the amount of petroleum-based feedstock used in carbon black production may be underreported by the U.S. Census Bureau. Finally, the amount of carbon black produced from the thermal black process and acetylene black process, although estimated to be a small percentage of the total production, is not known. Therefore, there is some uncertainty associated with the assumption that all of the carbon black is produced using the furnace black process.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-37. Petrochemical production CO_2 emissions were estimated to be between 2.0 and 3.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 27 percent below to 31 percent above the emission estimate of 2.7 Tg CO_2 Eq. Petrochemical production CH_4 emissions were estimated to be between 0.6 and 1.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 27 percent above the emission estimate of 0.8 Tg CO_2 Eq.

Table 4-37: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petrochemical Production and CO_2 Emissions from Carbon Black Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petrochemical Production	CO_2	2.7	2.0	3.6	-27%	+31%
Petrochemical Production	CH_4	0.8	0.6	1.1	-26%	+27%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the petrochemicals source category involve updating the methodology to use CH_4 emission factors for petrochemical production from the IPCC 2006 guidelines rather than the IPCC 1996 guidelines. Further future improvements involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from petrochemical production. Beginning in 2010, all U.S. petrochemical production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. petrochemical production industry, for example using a Tier 2 methodology to calculate emissions from the production of methanol, ethylene, propylene, ethylene dichloride, and ethylene oxide. In addition, the planned improvements include assessing the data EPA obtains to update data sources for acrylonitrile production in the United States.

4.10. Titanium Dioxide Production (IPCC Source Category 2B5)

Titanium dioxide (TiO_2) is a metal oxide manufactured from titanium ore, and is principally used as a pigment. Titanium dioxide is a principal ingredient in white paint, and is also used as a pigment in the manufacture of white paper, foods, and other products. There are two processes for making TiO_2: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related CO_2. The sulfate process does not use petroleum coke or other forms of C as a raw material and does not emit CO_2.

The chloride process is based on the following chemical reactions:

$$2\ FeTiO_3 + 7\ Cl_2 + 3\ C \rightarrow 2\ TiCl_4 + 2\ FeCl_3 + 3\ CO_2$$

$$2\ TiCl_4 + 2\ O_2 \rightarrow 2\ TiO_2 + 4\ Cl_2$$

The C in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and $FeTiO_3$ (the Ti-containing ore) to form CO_2. The majority of U.S. TiO_2 was produced in the United States through the chloride process, and a special grade of “calcined” petroleum coke is manufactured specifically for this purpose.

Emissions of CO_2 in 2009 were 1.5 Tg CO_2 Eq. (1,541 Gg), which represents an increase of 29 percent since 1990 (see Table 4-38).

Table 4-38: CO_2 Emissions from Titanium Dioxide (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	1.2	1,195
2000	1.8	1,752
2005	1.8	1,755
2006	1.8	1,836
2007	1.9	1,930
2008	1.8	1,809
2009	1.5	1,541

Methodology

Emissions of CO_2 from TiO_2 production were calculated by multiplying annual TiO_2 production by chloride-process-specific emission factors.

Data were obtained for the total amount of TiO_2 produced each year. For years previous to 2004, it was assumed that TiO_2 was produced using the chloride process and the sulfate process in the same ratio as the ratio of the total U.S. production capacity for each process. As of 2004, the last remaining sulfate-process plant in the United States had closed; therefore, 100 percent of post-2004 production uses the chloride process (USGS 2005). An emission factor of 0.4 metric tons C/metric ton TiO2 was applied to the estimated chloride-process production. It was assumed that all TiO_2 produced using the chloride process was produced using petroleum coke, although some TiO_2 may have been produced with graphite or other C inputs. The amount of petroleum coke consumed annually in TiO_2 production was calculated based on the assumption that the calcined petroleum coke used in the process is 98.4 percent C and 1.6 percent inert materials (Nelson 1969).

The emission factor for the TiO_2 chloride process was taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Titanium dioxide production data and the percentage of total TiO_2 production capacity that is chloride process for 1990 through 2008 (see Table 4-39) were obtained through the Minerals Yearbook: Titanium Annual Report (USGS 1991 through 2008). Production data in 2009 was obtained from the Minerals Commodity Summary: Titanium and Titanium Dioxide (USGS 2010). Due to lack of available 2009 capacity data at the time of publication, the 2008 capacity estimate is used as a proxy for 2009. Percentage chloride-process data were not available for 1990 through 1993, and data from the 1994 USGS Minerals Yearbook were used for these years. Because a sulfate-process plant closed in September 2001, the chloride-process percentage for 2001 was estimated based on a discussion with Joseph Gambogi (2002). By 2002, only one sulfate plant remained online in the United States and this plant closed in 2004 (USGS 2005).

Table 4-39: Titanium Dioxide Production (Gg)

Year	Gg
1990	979
2000	1,400
2005	1,310
2006	1,370
2007	1,440
2008	1,350
2009	1,150

Uncertainty and Time-Series Consistency

Although some TiO_2 may be produced using graphite or other C inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO_2 per unit of TiO_2 produced as compared to that generated through the use of petroleum coke in production. While the most accurate method to estimate emissions would be to base calculations on the amount of reducing agent used in each process rather than on the amount of TiO_2 produced, sufficient data were not available to do so.

Also, annual TiO_2 is not reported by USGS by the type of production process used (chloride or sulfate). Only the percentage of total production capacity by process is reported. The percent of total TiO_2 production capacity that was attributed to the chloride process was multiplied by total TiO_2 production to estimate the amount of TiO_2 produced using the chloride process (since, as of 2004, the last remaining sulfate-process plant in the United States closed). This assumes that the chloride-process plants and sulfate-process plants operate at the same level of utilization. Finally, the emission factor was applied uniformly to all chloride-process production, and no data were available to account for differences in production efficiency among chloride-process plants. In calculating the amount of petroleum coke consumed in chloride-process TiO_2 production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO_2 chloride process; however, this composition information was not available.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-40. Titanium dioxide consumption CO_2 emissions were estimated to be between 1.4 and 1.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 13 percent above the emission estimate of 1.5 Tg CO_2 Eq.

Table 4-40: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Titanium Dioxide Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Titanium Dioxide Production	CO_2	1.5	1.3	1.7	-13%	+13%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the titanium dioxide production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from titanium dioxide production. Beginning in 2010, all U.S. titanium dioxide production facilities using the chloride production process are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. titanium dioxide production industry, including improving the emission factors. In addition, the planned improvements include researching the significance of titanium-slag production in electric furnaces and synthetic-rutile production using the Becher process in the United States. Significant use of these production processes will be included in future estimates.

4.11. Carbon Dioxide Consumption (IPCC Source Category 2B5)

CO_2 is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, and refrigeration, and is also used in petroleum production for enhanced oil recovery (EOR). CO_2 used for EOR is injected into the underground reservoirs to increase the reservoir pressure to enable additional petroleum to be produced.

For the most part, CO_2 used in non-EOR applications will eventually be released to the atmosphere, and for the purposes of this analysis CO_2 used in commercial applications other than EOR is assumed to be emitted to the atmosphere. CO_2 used in EOR applications is discussed in the Energy Chapter under "Carbon Capture and Storage, including Enhanced Oil Recovery" and is not discussed in this section.

CO_2 is produced from naturally occurring CO_2 reservoirs, as a by-product from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a by-product from the production of crude oil and natural gas, which contain naturally occurring CO_2 as a component. Only CO_2 produced from naturally occurring CO_2 reservoirs and used in industrial applications other than EOR is included in this analysis. Neither by-product CO_2 generated from energy nor industrial production processes nor CO_2 separated from crude oil and natural gas are included in this analysis for a number of reasons. CO_2 captured from biogenic sources (e.g., ethanol production plants) is not included in the inventory. CO_2 captured from crude oil and gas production is used in EOR applications and is therefore reported in the Energy Chapter. Any CO_2 captured from industrial or energy production processes (e.g., ammonia plants, fossil fuel combustion) and used in non-EOR applications is assumed to be emitted to the atmosphere. The CO_2 emissions from such capture and use are therefore accounted for under Ammonia Production, Fossil Fuel Combustion, or other appropriate source category.[114]

CO_2 is produced as a by-product of crude oil and natural gas production. This CO_2 is separated from the crude oil and natural gas using gas processing equipment, and may be emitted directly to the atmosphere, or captured and reinjected into underground formations, used for EOR, or sold for other commercial uses. A further discussion of CO_2 used in EOR is described in the Energy Chapter under the text box titled "Carbon Dioxide Transport, Injection, and Geological Storage." The only CO_2 consumption that is accounted for in this analysis is CO_2 produced from naturally-occurring CO_2 reservoirs that is used in commercial applications other than EOR.

There are currently two facilities, one in Mississippi and one in New Mexico, producing CO_2 from naturally occurring CO_2 reservoirs for use in both EOR and in other commercial applications (e.g., chemical manufacturing, food production). There are other naturally occurring CO_2 reservoirs, mostly located in the western UnitedStates. Facilities are producing CO_2 from these natural reservoirs, but they are only producing CO_2 for EOR applications, not for other commercial applications (Allis et al. 2000). CO_2 production from these facilities is discussed in the Energy Chapter.

In 2009, the amount of CO_2 produced by the Mississippi and New Mexico facilities for commercial applications and subsequently emitted to the atmosphere was 1.8 Tg CO_2 Eq. (1,763 Gg) (see Table 4-41). This amount represents a decrease of one percent from the previous year and an increase of 24 percent since 1990. This increase was due to an in increase in production at the Mississippi facility, despite the decrease in the percent of the facility's total reported production that was used for commercial applications.

Table 4-41: CO_2 Emissions from CO_2 Consumption (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	1.4	1,416
2000	1.4	1,421
2005	1.3	1,321
2006	1.7	1,709
2007	1.9	1,867
2008	1.8	1,780
2009	1.8	1,763

Methodology

CO_2 emission estimates for 1990 through 2009 were based on production data for the two facilities currently producing CO_2 from naturally-occurring CO_2 reservoirs for use in non-EOR applications. Some of the CO_2 produced by these facilities is used for EOR and some is used in other commercial applications (e.g., chemical manufacturing, food production). It is assumed that 100 percent of the CO_2 production used in commercial applications other than EOR is eventually released into the atmosphere.

CO_2 production data for the Jackson Dome, Mississippi facility and the percentage of total production that was used for EOR and in non-EOR applications were obtained from the Advanced Resources Institute (ARI 2006, 2007) for 1990 to 2000 and from the Annual Reports for Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to 2009 (see Table 4-42). Denbury Resources reported the average CO_2 production in units of MMCF CO_2 per day for 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR. CO_2 production data for the Bravo Dome, New Mexico facility were obtained from the Advanced Resources International, Inc. (ARI 1990 through 2010). The percentage of total production that was used for EOR and in non-EOR applications were obtained from the New Mexico Bureau of Geology and Mineral Resources (Broadhead 2003 and New Mexico Bureau of Geology and Mineral Resources 2006).

Table 4-42: CO_2 Production (Gg CO_2) and the Percent Used for Non-EOR Applications for Jackson Dome and

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[114] There are currently four known electric power plants operating in the U.S. that capture CO_2 for use as food-grade CO_2 or other industrial processes; however, insufficient data prevents estimating emissions from these activities as part of Carbon Dioxide Consumption.

Bravo Dome

Year	Jackson Dome CO_2 Production (Gg)	Jackson Dome % Used for Non-EOR	Bravo Dome CO_2 Production (Gg)	Bravo Dome % Used for Non-EOR
1990	1,353	100%	6,301	1%
2000	1,353	100%	6,834	1%
2005	4,678	27%	5,799	1%
2006	6,610	25%	5,613	1%
2007	9,529	19%	5,605	1%
2008	12,312	14%	5,605	1%
2009	13,201	13%	4,639	1%

Uncertainty and Time-Series Consistency

Uncertainty is associated with the number of facilities that are currently producing CO_2 from naturally occurring CO_2 reservoirs for commercial uses other than EOR, and for which the CO_2 emissions are not accounted for elsewhere. Research indicates that there are only two such facilities, which are in New Mexico and Mississippi; however, additional facilities may exist that have not been identified. In addition, it is possible that CO_2 recovery exists in particular production and end-use sectors that are not accounted for elsewhere. Such recovery may or may not affect the overall estimate of CO_2 emissions from that sector depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether CO_2 is being recovered from other facilities for application to end uses that are not accounted for elsewhere.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-43. CO_2 consumption CO_2 emissions were estimated to be between 1.3 and 2.3 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 30 percent above the emission estimate of 1.8 Tg CO_2 Eq.

Table 4-43: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from CO_2 Consumption (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
CO_2 Consumption	CO_2	1.8	1.3	2.3	-26%	+30%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the Carbon Dioxide Consumption source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from carbon dioxide consumption. Beginning in 2010, all U.S. CO_2 producers are required to monitor, calculate and report the quantity of CO_2 supplied to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 on CO_2 supplied from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from consumption of CO_2.

4.12. Phosphoric Acid Production (IPCC Source Category 2B5)

Phosphoric acid (H_3PO_4) is a basic raw material in the production of phosphate-based fertilizers. Phosphate rock is mined in Florida, North Carolina, Idaho, Utah, and other areas of the United States and is used primarily as a raw material for phosphoric acid production. The production of phosphoric acid from phosphate rock produces byproduct gypsum ($CaSO_4$-$2H_2O$), referred to as phosphogypsum.

The composition of natural phosphate rock varies depending upon the location where it is mined. Natural phosphate rock mined in the United States generally contains inorganic C in the form of calcium carbonate (limestone) and also may contain organic C. The chemical composition of phosphate rock (francolite) mined in Florida is:

$$Ca_{10-x-y}\ Na_x\ Mg_y\ (PO_4)_{6-x}(CO_3)_xF_{2+0.4x}$$

The calcium carbonate component of the phosphate rock is integral to the phosphate rock chemistry. Phosphate rock can also contain organic C that is physically incorporated into the mined rock but is not an integral component of the phosphate rock chemistry. Phosphoric acid production from natural phosphate rock is a source of CO_2 emissions, due to the chemical reaction of the inorganic C (calcium carbonate) component of the phosphate rock.

The phosphoric acid production process involves chemical reaction of the calcium phosphate ($Ca_3(PO_4)_2$) component of the phosphate rock with sulfuric acid (H_2SO_4) and recirculated phosphoric acid (H_3PO_4) (EFMA 2000). The primary chemical reactions for the production of phosphoric acid from phosphate rock are:

$$Ca_3(PO_4)_2 + 4H_3PO_4 \rightarrow 3Ca(H_2PO_4)_2$$

$$3Ca(H_2PO_4)_2 + 3H_2SO_4 + 6H_2O \rightarrow 3CaSO_4 \bullet 6H_2O + 6H_3PO_4$$

The limestone ($CaCO_3$) component of the phosphate rock reacts with the sulfuric acid in the phosphoric acid production process to produce calcium sulfate (phosphogypsum) and CO_2. The chemical reaction for the limestone-sulfuric acid reaction is:

$$CaCO_3 + H_2SO_4 + H_2O \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

Total marketable phosphate rock production in 2009 was 27.2 million metric tons (USGS 2010). Approximately 87 percent of domestic phosphate rock production was mined in Florida and North Carolina, while approximately 13 percent of production was mined in Idaho and Utah. Total imports of phosphate rock in 2009 were 1.8 million metric tons (USGS 2010). The vast majority, 99 percent, of imported phosphate rock is sourced from Morocco (USGS 2005). Marketable phosphate rock production, including domestic production and imports for consumption, decreased by 13.6 percent between 2008 and 2009. Over the 1990 to 2009 period, production has decreased by 34 percent. Total CO_2 emissions from phosphoric acid production were 1.0 Tg CO_2 Eq. (1,035 Gg) in 2009 (see Table 4-44). According to USGS 2010, the weak market conditions of phosphate rock in the U.S. in 2009 were a result of the global economic crisis that started in late 2008 and carried into 2009.

Table 4-44: CO_2 Emissions from Phosphoric Acid Production (Tg CO_2 Eq. and Gg)

Year	Tg CO2 Eq.	Gg
1990	1.5	1,529
2000	1.4	1,382
2005	1.4	1,386
2006	1.2	1,167
2007	1.2	1,166
2008	1.2	1,187
2009	1.0	1,035

Methodology

CO_2 emissions from production of phosphoric acid from phosphate rock are calculated by multiplying the average amount of calcium carbonate contained in the natural phosphate rock by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for domestic production and net imports for consumption.

The CO_2 emissions calculation methodology is based on the assumption that all of the inorganic C (calcium carbonate) content of the phosphate rock reacts to CO_2 in the phosphoric acid production process and is emitted with the stack gas. The methodology also assumes that none of the organic C content of the phosphate rock is converted to CO_2 and that all of the organic C content remains in the phosphoric acid product.

From 1993 to 2004, the *USGS Mineral Yearbook: Phosphate Rock* disaggregated phosphate rock mined annually in Florida and North Carolina from phosphate rock mined annually in Idaho and Utah, and reported the annual amounts of phosphate rock exported and imported for consumption (see Table 4-45). For the years 1990, 1991, 1992, 2005, 2006, and 2007 only nationally aggregated mining data was reported by USGS. For these years, the breakdown of phosphate rock mined in Florida and North Carolina, and the amount mined in Idaho and Utah, are approximated using 1993 to 2004 data. Data for domestic production of phosphate rock, exports of phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for 1990 through 2008 were obtained from *USGS Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2010). 2009 data were obtained from *USGS Minerals Commodity Summary: Phosphate Rock* (USGS 2010). From 2004 through 2009, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2005 through 2010).

The carbonate content of phosphate rock varies depending upon where the material is mined. Composition data for domestically mined and imported phosphate rock were provided by the Florida Institute of Phosphate Research (FIPR 2003). Phosphate rock mined in Florida contains approximately 1 percent inorganic C, and phosphate rock imported from Morocco contains approximately 1.46 percent inorganic C. Calcined phosphate rock mined in North Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic C, respectively (see Table 4-46).

Carbonate content data for phosphate rock mined in Florida are used to calculate the CO_2 emissions from consumption of phosphate rock mined in Florida and North Carolina (87 percent of domestic production) and carbonate content data for phosphate rock mined in Morocco are used to calculate CO_2 emissions from consumption of imported phosphate rock. The CO_2 emissions calculation is based on the assumption that all of the domestic production of phosphate rock is used in uncalcined form. As of 2006, the USGS noted that one phosphate rock producer in Idaho produces calcined phosphate rock; however, no production data were available for this single producer (USGS 2006). Carbonate content data for uncalcined phosphate rock mined in Idaho and Utah (13 percent of domestic production) were not available, and carbonate content was therefore estimated from the carbonate content data for calcined phosphate rock mined in Idaho.

Table 4-45: Phosphate Rock Domestic Production, Exports, and Imports (Gg)

Location/Year	1990	2000	2005	2006	2007	2008	2009
U.S. Production[a]	49,800	37,370	36,100	30,100	29,700	30,200	27,200
FL & NC	42,494	31,900	31,227	26,037	25,691	26,123	23,528
ID & UT	7,306	5,470	4,874	4,064	4,010	4,077	3,672
Exports—FL & NC	6,240	299	-	-	-	-	-
Imports—Morocco	451	1,930	2,630	2,420	2,670	2,754	1,800
Total U.S. Consumption	**44,011**	**39,001**	**38,730**	**32,520**	**32,370**	**32,954**	**29,000**

[a] USGS does not disaggregate production data regionally (FL & NC and ID & UT) for 1990, 2005, 2006, and 2007. Data for those years are estimated based on the remaining time series distribution.

- Assumed equal to zero.

Table 4-46: Chemical Composition of Phosphate Rock (percent by weight)

Composition	Central Florida	North Florida	North Carolina (calcined)	Idaho (calcined)	Morocco
Total Carbon (as C)	1.60	1.76	0.76	0.60	1.56
Inorganic Carbon (as C)	1.00	0.93	0.41	0.27	1.46
Organic Carbon (as C)	0.60	0.83	0.35	-	0.10
Inorganic Carbon (as CO_2)	3.67	3.43	1.50	1.00	5.00

Source: FIPR 2003

- Assumed equal to zero.

Uncertainty and Time-Series Consistency

Phosphate rock production data used in the emission calculations were developed by the USGS through monthly and semiannual voluntary surveys of the active phosphate rock mines during 2009. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006 only total U.S. phosphate rock production were reported. Regional production for 2008 was estimated based on regional production data from previous years and multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the estimated 2008 regional production data represents actual production in those regions. Total U.S. phosphate rock production data are not considered to be a significant source of uncertainty because all the domestic phosphate rock producers report their annual production to the USGS. Data for exports of phosphate rock used in the emission calculation are reported by phosphate rock producers and are not considered to be a significant source of uncertainty. Data for imports for consumption are based on international trade data collected by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of uncertainty.

An additional source of uncertainty in the calculation of CO_2 emissions from phosphoric acid production is the carbonate composition of phosphate rock; the composition of phosphate rock varies depending upon where the material is mined, and may also vary over time. Another source of uncertainty is the disposition of the organic C content of the phosphate rock. A representative of the FIPR indicated that in the phosphoric acid production process, the organic C content of the mined phosphate rock generally remains in the phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003a). Organic C is therefore not included in the calculation of CO_2 emissions from phosphoric acid production.

A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result in conversion of some of the organic C in the phosphate rock into CO_2. However, according to the USGS, only one producer in Idaho is currently calcining phosphate rock, and no data were available concerning the annual production of this single producer (USGS 2005). For available years, total production of phosphate rock in Utah and Idaho combined amounts to approximately 13 percent of total domestic production on average (USGS 1994 through 2005).

Finally, USGS indicated that approximately 7 percent of domestically-produced phosphate rock is used to manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS 2006). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO_2 in the elemental phosphorus production process. The calculation for CO_2 emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO_2 emissions from 100 percent of the inorganic C content in phosphate rock, but none from the organic C content.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-47. Phosphoric acid production CO_2 emissions were estimated to be between 0.9 and 1.2 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 18 percent below and 19 percent above the emission estimate of 1.0 Tg CO_2 Eq.

Table 4-47: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Phosphoric Acid Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Phosphoric Acid Production	CO_2	1.0	0.9	1.2	-18%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the phosphoric acid production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from phosphoric acid production. Beginning in 2010, all U.S. phosphoric acid producers are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. phosphoric acid production industry. Currently, data sources for the carbonate content of the phosphate rock are limited. If additional data sources are found, this information will be incorporated into future estimates. Additionally, as future improvement to the phosphoric acid uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify uncertainty ranges associated with phosphate rock imports and exports.

4.13. Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production

The production of iron and steel is an energy-intensive activity that also generates process-related emissions of CO_2 and CH_4. Process emissions occur at each step of steel production from the production of raw materials to the refinement of iron to the making of crude steel. In the United States, steel is produced through both primary and secondary processes. Historically, primary production—using a basic oxygen furnace (BOF) with pig iron as the primary feedstock—has been the dominant method. But secondary production through the use scrap steel and electric arc furnaces (EAFs) has increased significantly in recent years due to the economic advantages of steel recycling, which has been driven by the increased availability of scrap steel. Total production of crude steel in the United States in the time period between 2001 and 2008 ranged from a low of 99,321,000 tons to a high of 109,879,000 tons (2001 and 2004, respectively). But due to the decrease in demand caused by the global economic downturn, crude steel production in the United States decreased to 65,460,000 tons in 2009 (AISI 2010).

Metallurgical coke is an important input in the production of iron and steel. Coke is used to produce iron or pig iron feedstock from raw iron ore. The production of metallurgical coke from coking coal occurs both on-site at "integrated" iron and steel plants and off-site at "merchant" coke plants. Metallurgical coke is produced by heating coking coal in a coke oven in a low-oxygen environment. The process drives off the volatile components of the coking coal and produces coal (metallurgical) coke. Carbon containing byproducts of the metallurgical coke manufacturing process include coke oven gas, coal tar, coke breeze (small-grade coke oven coke with particle size <5mm) and light oil. Coke oven gas is recovered and used for underfiring the coke ovens and within the iron and steel mill. Small amounts of coke oven gas are also sold as synthetic natural gas outside of iron and steel mills (and are accounted for in the Energy chapter). Coal tar is used as a raw material to produce anodes used for primary aluminum production, electric arc furnace (EAF) steel production, and other electrolytic processes, and also is used in the production of other coal tar products. Light oil is sold to petroleum refiners who use the material as an additive for gasoline. The metallurgical coke production process produces CO_2 emissions and fugitive CH_4 emissions.

Iron is produced by first reducing iron oxide (iron ore) with metallurgical coke in a blast furnace. Iron can be introduced into the blast furnace in the form of raw iron ore, taconite pellets (9-16mm iron-containing spheres), briquettes, or sinter. In addition to metallurgical coke and iron, other inputs to the blast furnace include natural gas, fuel oil, and coke oven gas. The carbon in the metallurgical coke used in the blast furnace combines with oxides in the iron ore in a reducing atmosphere to produce blast furnace gas containing carbon monoxide (CO) and CO_2. The CO is then converted and emitted as CO_2 when combusted to either pre-heat the blast air used in the blast furnace or for other purposes at the steel mill. This pig iron or crude iron that is produced from this process contains about 3 to 5 percent carbon by weight. The pig iron production process in a blast furnace produces CO_2 emissions and fugitive CH_4 emissions.

Iron can also be produced through the direct reduction process; wherein, iron ore is reduced to metallic iron in the solid state at process temperatures less than 1000°C. Direct reduced iron production results in process emissions of CO_2 and emissions of CH_4 through the consumption of natural gas used during the reduction process.

Sintering is a thermal process by which fine iron-bearing particles, such as air emission control system dust, are baked, which causes the material to agglomerate into roughly one-inch pellets that are then recharged into the blast furnace for pig iron production. Iron ore particles may also be formed into larger pellets or briquettes by mechanical means, and then agglomerated by heating. The agglomerate is then crushed and screened to produce an iron-bearing feed that is charged into the blast furnace. The sintering process produces CO_2 and fugitive CH_4 emissions through the consumption of carbonaceous inputs (e.g., coke breeze) during the sintering process.

Steel is produced from varying levels of pig iron and scrap steel in specialized BOF and EAF steel-making furnaces. Carbon inputs to BOF steel-making furnaces include pig iron and scrap steel as well as natural gas, fuel oil, and fluxes (e.g., limestone, dolomite). In a BOF, the carbon in iron and scrap steel combines with high-purity oxygen to reduce the carbon content of the metal to the amount desired for the specified grade of steel. EAFs use carbon electrodes, charge carbon and other materials (e.g., natural gas) to aid in melting metal inputs (primarily recycled scrap steel), which are refined and alloyed to produce the desired grade of steel. CO_2 emissions occur in BOFs through the reduction process. In EAFs, CO_2 emissions result primarily from the consumption of carbon electrodes and also from the consumption of supplemental materials used to augment the melting process.

In addition to the production processes mentioned above, CO_2 is also generated at iron and steel mills through the consumption of process by-products (e.g., blast furnace gas, coke oven gas) used for various purposes including heating, annealing, and electricity generation. Process by-products sold for use as synthetic natural gas are deducted and reported in the Energy chapter (emissions associated with natural gas and fuel oil consumption for these purposes are reported in the Energy chapter).

The majority of CO_2 emissions from the iron and steel production process come from the use of metallurgical coke in the production of pig iron and from the consumption of other process by-products at the iron and steel mill, with lesser amounts emitted from the use of flux and from the removal of carbon from pig iron used to produce steel. Some carbon is also stored in the finished iron and steel products.

According to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), the production of metallurgical coke from coking coal is considered to be an energy use of fossil fuel and the use of coke in iron and steel production is considered to be an industrial process source. Therefore, the Guidelines suggest that emissions from the production of metallurgical coke should be reported separately in the Energy source, while emissions from coke consumption in iron and steel production should be reported in the industrial process source. However, the approaches and emission estimates for both metallurgical coke production and iron and steel production are both presented here because the activity data used to estimate emissions from metallurgical coke production have significant overlap with activity data used to estimate iron and steel production emissions. Further, some by-products (e.g., coke oven gas) of the metallurgical coke production process are consumed during iron and steel production, and some by-products of the iron and steel production process (e.g., blast furnace gas) are consumed during metallurgical coke production. Emissions associated with the consumption of these by-products are attributed to point of consumption. As an example, CO_2 emissions associated with the combustion of coke oven gas in the blast furnace during pig iron production are attributed to pig iron production. Emissions associated with the use of conventional fuels (e.g., natural gas and fuel oil) for electricity generation, heating and annealing, or other miscellaneous purposes downstream of the iron and steelmaking furnaces are reported in the Energy chapter.

Metallurgical Coke Production

Emissions of CO_2 and CH_4 from metallurgical coke production in 2009 were 1.0 Tg CO_2 Eq. (956 Gg) and less than 0.002 Tg CO_2 Eq. (less than 0.00003 Gg), respectively (see Table 4-48 and Table 4-49), totaling 1.0 Tg CO_2 Eq. Emissions decreased in 2009, and have decreased overall since 1990. In 2009, domestic coke production decreased by 29 percent and has decreased overall since 1990. Coke production in 2009 was 46 percent lower than in 2000 and 60 percent below 1990. Overall, emissions from metallurgical coke production have declined by 61 percent (1.5 Tg CO_2 Eq.) from 1990 to 2009.

Table 4-48: CO_2 and CH_4 Emissions from Metallurgical Coke Production (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2.5	2.2	2.0	1.9	2.1	2.3	1.0
CH_4	+	+	+	+	+	+	+
Total	**2.5**	**2.2**	**2.0**	**1.9**	**2.1**	**2.3**	**1.0**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 4-49: CO_2 and CH_4 Emissions from Metallurgical Coke Production (Gg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2,470	2,195	2,043	1,919	2,054	2,334	956
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg

Iron and Steel Production

Emissions of CO_2 and CH_4 from iron and steel production in 2009 were 40.9 Tg CO_2 Eq. (40,914 Gg) and 0.4 Tg CO_2 Eq. (17.4 Gg), respectively (see Table 4-50 through Table 4-53), totaling approximately 41 Tg CO_2 Eq. Emissions decreased in 2009—largely due to decreased steel production associated with the global economic downturn—and have decreased overall since 1990 due to restructuring of the industry, technological improvements, and increased scrap steel utilization. CO_2 emission estimates include emissions from the consumption of carbonaceous materials in the blast furnace, EAF, and BOF as well as blast furnace gas and coke oven gas consumption for other activities at the steel mill.

In 2009, domestic production of pig iron decreased by 44 percent. Overall, domestic pig iron production has declined since the 1990s. Pig iron production in 2009 was 60 percent lower than in 2000 and 62 percent below 1990. CO_2 emissions from steel production have declined by 15 percent (1.1 Tg CO_2 Eq.) since 1990, while overall CO_2 emissions from iron and steel production have declined by 58 percent (56.1 Tg CO_2 Eq.) from 1990 to 2009.

Table 4-50: CO_2 Emissions from Iron and Steel Production (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	2.4	2.2	1.7	1.4	1.4	1.3	0.8
Iron Production	47.9	33.8	19.6	23.9	27.3	25.7	15.9
Steel Production	7.5	7.9	8.5	8.9	9.4	7.5	6.4
Other Activities[a]	39.3	39.9	34.2	32.6	31.0	29.1	17.8
Total	**97.1**	**83.7**	**63.9**	**66.9**	**69.0**	**63.7**	**40.9**

Note: Totals may not sum due to independent rounding.

[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Table 4-51: CO_2 Emissions from Iron and Steel Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	2,448	2,158	1,663	1,418	1,383	1,299	763
Iron Production	47,880	33,818	19,570	23,928	27,262	25,696	15,948
Steel Production	7,475	7,887	8,489	8,924	9,382	7,541	6,389
Other Activities [a]	39,256	39,877	34,160	32,583	30,964	29,146	17,815
Total	**97,058**	**83,740**	**63,882**	**66,852**	**68,991**	**63,682**	**40,914**

Note: Totals may not sum due to independent rounding.

[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Table 4-52: CH_4 Emissions from Iron and Steel Production (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	+	+	+	+	+	+	+
Iron Production	0.9	0.9	0.7	0.7	0.7	0.6	0.4
Total	**1.0**	**0.9**	**0.7**	**0.7**	**0.7**	**0.6**	**0.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 4-53: CH_4 Emissions from Iron and Steel Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	0.9	0.7	0.6	0.5	0.5	0.4	0.3
Iron Production	44.7	43.1	33.5	34.1	32.7	30.4	17.1
Total	**45.6**	**43.8**	**34.1**	**34.6**	**33.2**	**30.8**	**17.4**

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates presented in this chapter are based on the methodologies provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), which call for a mass balance accounting of the carbonaceous inputs and outputs during the iron and steel production process and the metallurgical coke production process.

Metallurgical Coke Production

Coking coal is used to manufacture metallurgical (coal) coke that is used primarily as a reducing agent in the production of iron and steel, but is also used in the production of other metals including lead and zinc (see Lead

Production and Zinc Production in this chapter). Emissions associated with producing metallurgical coke from coking coal are estimated and reported separately from emissions that result from the iron and steel production process. To estimate emission from metallurgical coke production, a Tier 2 method provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) was utilized. The amount of carbon contained in materials produced during the metallurgical coke production process (i.e., coke, coke breeze, coke oven gas, and coal tar) is deducted from the amount of carbon contained in materials consumed during the metallurgical coke production process (i.e., natural gas, blast furnace gas, coking coal). Light oil, which is produced during the metallurgical coke production process, is excluded from the deductions due to data limitations. The amount of carbon contained in these materials is calculated by multiplying the material-specific carbon content by the amount of material consumed or produced (see Table 4-54). The amount of coal tar produced was approximated using a production factor of 0.03 tons of coal tar per ton of coking coal consumed. The amount of coke breeze produced was approximated using a production factor of 0.075 tons of coke breeze per ton of coking coal consumed. Data on the consumption of carbonaceous materials (other than coking coal) as well as coke oven gas production were available for integrated steel mills only (i.e., steel mills with co-located coke plants). Therefore, carbonaceous material (other than coking coal) consumption and coke oven gas production were excluded from emission estimates for merchant coke plants. Carbon contained in coke oven gas used for coke-oven underfiring was not included in the deductions to avoid double-counting.

Table 4-54: Material Carbon Contents for Metallurgical Coke Production

Material	**kg C/kg**
Coal Tar	0.62
Coke	0.83
Coke Breeze	0.83
Coking Coal	0.73
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production processes for metallurgical coke production results in fugitive emissions of CH_4, which are emitted via leaks in the production equipment rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors (0.1 g CH_4 per metric ton) taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for metallurgical coke production.

Data relating to the mass of coking coal consumed at metallurgical coke plants and the mass of metallurgical coke produced at coke plants were taken from the Energy Information Administration (EIA), Quarterly Coal Report October through December (EIA 1998 through 2004) and January through March (EIA 2010a) (see Table 4-55). Data on the volume of natural gas consumption, blast furnace gas consumption, and coke oven gas production for metallurgical coke production at integrated steel mills were obtained from the American Iron and Steel Institute (AISI), *Annual Statistical Report* (AISI 2004 through 20010) and through personal communications with AISI (2008b) (see Table 4-56). The factor for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (2008b). The factor for the quantity of coke breeze produced per ton of coking coal consumed was obtained through Table 2-1 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). Data on natural gas consumption and coke oven gas production at merchant coke plants were not available and were excluded from the emission estimate. Carbon contents for coking coal, metallurgical coke, coal tar, coke oven gas, and blast furnace gas were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C content for coke breeze was assumed to equal the C content of coke.

Table 4-55: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Metallurgical Coke Production (Thousand Metric Tons)

Source/Activity Data	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Metallurgical Coke Production									
Coking Coal Consumption at Coke Plants	35,269		26,254		21,259	20,827	20,607	20,022	13,904
Coke Production at Coke Plants	25,054		18,877		15,167	14,882	14,698	14,194	10,109
Coal Breeze Production	2,645		1,969		1,594	1,562	1,546	1,502	1,043
Coal Tar Production	1,058		788		638	625	618	601	417

Table 4-56: Production and Consumption Data for the Calculation of CO_2 Emissions from Metallurgical Coke Production (million ft^3)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coke Oven Gas Production[a]	250,767	149,477	114,213	114,386	109,912	103,191	66,155
Natural Gas Consumption	599	180	2,996	3,277	3,309	3,134	2,121
Blast Furnace Gas Consumption	24,602	26,075	4,460	5,505	5,144	4,829	2,435

[a] Includes coke oven gas used for purposes other than coke oven underfiring only.

Iron and Steel Production

Emissions of CO_2 from sinter production and direct reduced iron production were estimated by multiplying total national sinter production and the total national direct reduced iron production by Tier 1 CO_2 emission factors (see Table 4-57). Because estimates of sinter production and direct reduced iron production were not available, production was assumed to equal consumption.

Table 4-57: CO_2 Emission Factors for Sinter Production and Direct Reduced Iron Production

Material Produced	Metric Ton CO_2/Metric Ton
Sinter	0.2
Direct Reduced Iron	0.7

Source: IPCC 2006, Table 4.1.

To estimate emissions from pig iron production in the blast furnace, the amount of C contained in the produced pig iron and blast furnace gas were deducted from the amount of C contained in inputs (i.e., metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, direct coal injection). The C contained in the pig iron, blast furnace gas, and blast furnace inputs was estimated by multiplying the material-specific carbon content by each material type (see Table 4-58). Carbon in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO_2 during this process.

Emissions from steel production in EAFs were estimated by deducting the C contained in the steel produced from the carbon contained in the EAF anode, charge carbon, and scrap steel added to the EAF. Small amounts of C from direct reduced iron, pig iron, and flux additions to the EAFs were also included in the EAF calculation. For BOFs, estimates of C contained in BOF steel were deducted from carbon contained in inputs such as natural gas, coke oven gas, fluxes, and pig iron. In each case, the C was calculated by multiplying material-specific carbon contents by each material type (see Table 4-58). For EAFs, the amount of EAF anode consumed was approximated by multiplying total EAF steel production by the amount of EAF anode consumed per metric ton of steel produced (0.002 metric tons EAF anode per metric ton steel produced (AISI 2008b)). The amount of flux (e.g., limestone and dolomite) used during steel manufacture was deducted from the Limestone and Dolomite Use source category to avoid double-counting.

CO_2 emissions from the consumption of blast furnace gas and coke oven gas for other activities occurring at the steel mill were estimated by multiplying the amount of these materials consumed for these purposes by the material-specific C content (see Table 4-58).

CO_2 emissions associated with the sinter production, direct reduced iron production, pig iron production, steel production, and other steel mill activities were summed to calculate the total CO_2 emissions from iron and steel production (see Table 4-50and Table 4-51).

Table 4-58: Material Carbon Contents for Iron and Steel Production

Material	kg C/kg
Coke	0.83
Direct Reduced Iron	0.02
Dolomite	0.13
EAF Carbon Electrodes	0.82
EAF Charge Carbon	0.83
Limestone	0.12
Pig Iron	0.04

Steel	0.01
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production processes for sinter and pig iron result in fugitive emissions of CH_4, which are emitted via leaks in the production equipment rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for sinter production and the 1995 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1995) (see Table 4-59) for pig iron production. The production of direct reduced iron also results in emissions of CH_4 through the consumption of fossil fuels (e.g., natural gas); however, these emissions estimates are excluded due to data limitations.

Table 4-59: CH_4 Emission Factors for Sinter and Pig Iron Production

Material Produced	Factor	Unit
Pig Iron	0.9	g CH_4/kg
Sinter	0.07	kg CH_4/metric ton

Source: Sinter (IPCC 2006, Table 4.2), Pig Iron (IPCC/UNEP/OECD/IEA 1995, Table 2.2)

Sinter consumption and direct reduced iron consumption data were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-60). Data on direct reduced iron consumed in EAFs were not available for the years 1990, 1991, 1999, 2006, 2007, 2008, and 2009. EAF direct reduced iron consumption in 1990 and 1991 were assumed to equal consumption in 1992, and consumption in 1999 was assumed to equal the average of 1998 and 2000. EAF consumption in 2006, 2007, 2008, and 2009 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the EAF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). Data on direct reduced iron consumed in BOFs were not available for the years 1990 through 1994, 1999, 2006, 2007, 2008, and 2009. BOF direct reduced iron consumption in 1990 through 1994 was assumed to equal consumption in 1995, and consumption in 1999 was assumed to equal the average of 1998 and 2000. BOF consumption in 2006, 2007, and 2008 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). The Tier 1 CO_2 emission factors for sinter production and direct reduced iron production were obtained through the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Data for pig iron production, coke, natural gas, fuel oil, sinter, and pellets consumed in the blast furnace; pig iron production; and blast furnace gas produced at the iron and steel mill and used in the metallurgical coke ovens and other steel mill activities were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-61). Data for EAF steel production, flux, EAF charge carbon, direct reduced iron, pig iron, scrap steel, and natural gas consumption as well as EAF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2011). The factor for the quantity of EAF anode consumed per ton of EAF steel produced was provided by AISI (AISI 2008b). Data for BOF steel production, flux, direct reduced iron, pig iron, scrap steel, natural gas, natural ore, pellet sinter consumption as well as BOF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Because data on pig iron consumption and scrap steel consumption in BOFs and EAFs were not available for 2006, 2007, and 2009, values for these years were calculated by multiplying the total pig iron and scrap steel consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF and EAF shares of total pig iron and scrap consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of pig iron and scrap steel). Because pig iron consumption in EAFs was also not available in 2003 and 2004, the average of 2002 and 2005 pig iron consumption data were used. Data on coke oven gas and blast furnace gas consumed at the iron and steel mill other than in the EAF, BOF, or blast furnace were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained through EIA's *Natural Gas Annual 2009* (EIA 2010b). C contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon, limestone, dolomite, pig iron, and steel were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C contents for natural gas, fuel oil, and direct injection coal as well as the heat contents for the same fuels were provided by EIA (1992, 2010c). Heat contents for coke oven gas and blast furnace gas were provided in Table 2-2 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000).

Table 4-60: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Iron and Steel Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Sinter Production							
Sinter Production	12,239	10,788	8,315	7,088	6,914	6,497	3,814
Direct Reduced Iron Production							
Direct Reduced Iron Production	936	1,914	1,633	1,497	2,087	1,769	1,243
Pig Iron Production							
Coke Consumption	24,946	19,215	13,832	14,684	15,039	14,251	8,572
Pig Iron Production	49,669	47,888	37,222	37,904	36,337	33,730	19,019
Direct Injection Coal Consumption	1,485	3,012	2,573	2,526	2,734	2,578	1,674
EAF Steel Production							
EAF Anode and Charge Carbon Consumption	67	96	1,127	1,245	1,214	1,109	845
Scrap Steel Consumption	35,743	43,001	37,558	38,033	40,845	40,824	35,472
Flux Consumption	319	654	695	671	567	680	476
EAF Steel Production	33,511	47,860	52,194	56,071	57,004	52,791	36,700
BOF Steel Production							
Pig Iron Consumption	46,564	46,993	32,115	32,638	33,773	29,322	23,134
Scrap Steel Consumption	14,548	14,969	11,612	11,759	12,628	8,029	6,641
Flux Consumption	576	978	582	610	408	431	318
BOF Steel Production	43,973	53,965	42,705	42,119	41,099	39,105	22,659

Table 4-61: Production and Consumption Data for the Calculation of CO_2 Emissions from Iron and Steel Production (million ft^3 unless otherwise specified)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Pig Iron Production							
Natural Gas Consumption	56,273	91,798	59,844	58,344	56,112	53,349	35,933
Fuel Oil Consumption (thousand gallons)	163,397	120,921	16,170	87,702	84,498	55,552	23,179
Coke Oven Gas Consumption	22,033	13,702	16,557	16,649	16,239	15,336	9,951
Blast Furnace Gas Production	1,439,380	1,524,891	1,299,980	1,236,526	1,173,588	1,104,674	672,486
EAF Steel Production							
Natural Gas Consumption	9,604	13,717	14,959	16,070	16,337	15,130	10,518
BOF Steel Production							
Natural Gas Consumption	6,301	6,143	5,026	5,827	11,740	-4,304[a]	-2,670[a]
Coke Oven Gas Consumption	3,851	640	524	559	525	528	373
Other Activities							
Coke Oven Gas Consumption	224,883	135,135	97,132	97,178	93,148	87,327	55,831
Blast Furnace Gas Consumption	1,414,778	1,498,816	1,295,520	1,231,021	1,168,444	1,099,845	670,051

[a] EPA is continuing to work with AISI to investigate why this value is negative.

Uncertainty and Time-Series Consistency

The estimates of CO_2 and CH_4 emissions from metallurgical coke production are based on material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO_2 from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e, coking coal consumption and metallurgical coke production) only.

The estimates of CO_2 emissions from iron and steel production are based on material production and consumption data and average C contents. There is uncertainty associated with the assumption that direct reduced iron and sinter consumption are equal to production. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal. Some of this coal may be used for electricity generation. There is also uncertainty associated with the C contents for pellets, sinter, and natural ore, which are assumed to equal the C contents of direct reduced iron. For EAF steel production there is uncertainty associated with the amount of EAF anode and charge C consumed due to inconsistent data throughout the time series. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (e.g., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and C contents produce a relatively accurate estimate of CO_2 emissions. However, there are uncertainties associated with each.

For the purposes of the CH_4 calculation from iron and steel production it is assumed that all of the CH_4 escapes as fugitive emissions and that none of the CH_4 is captured in stacks or vents. Additionally, the CO_2 emissions calculation is not corrected by subtracting the C content of the CH_4, which means there may be a slight double counting of C as both CO_2 and CH_4.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-62 for metallurgical coke production and iron and steel production. Total CO_2 emissions from metallurgical coke production and iron and steel production were estimated to be between 35.2 and 48.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 16 percent below and 16 percent above the emission estimate of 41.9 Tg CO_2 Eq. Total CH_4 emissions from metallurgical coke production and iron and steel production were estimated to be 0.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 23 percent above the emission estimate of 0.4 Tg CO_2 Eq.

Table 4-62: Tier 2 Quantitative Uncertainty Estimates for CO_2 and CH_4 Emissions from Iron and Steel Production and Metallurgical Coke Production (Tg. CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Metallurgical Coke & Iron and Steel Production	CO_2	41.9	35.2	48.4	-16%	+16%
Metallurgical Coke & Iron and Steel Production	CH_4	0.4	0.3	0.4	-21%	+23%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the Iron and Steel production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from iron and steel production. Beginning in 2010, all U.S. iron and steel producing facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. iron and steel industry. Specifically, plans include attributing emissions estimates for the production of metallurgical coke to the Energy chapter as well as identifying the amount of carbonaceous materials, other than coking coal, consumed at merchant coke plants. Additional improvements include identifying the amount of coal used for direct injection and the amount of coke breeze, coal tar, and light oil produced during coke production. Efforts will also be made to identify inputs for preparing Tier 2 estimates for sinter and direct reduced iron production, as well as identifying information to better characterize emissions from the use of process gases and fuels within the Energy and Industrial Processes chapters.

Recalculations Discussion

In the previous Inventory, coal tar production and coke breeze production were incorrectly estimated by multiplying the respective production factors by U.S. coke production at coke plants rather than U.S. coking coal consumption at coke plants (to which the coal tar and coke breeze production factors should be applied). This issue has been corrected and decreased the 1990 through 2008 emissions from metallurgical coke production by an average of 53 percent per year relative to the previous Inventory. The total 1990 through 2008 emissions for metallurgical coke and iron and steel production decreased by an average of 3 percent per year relative to the previous Inventory.

4.14. Ferroalloy Production (IPCC Source Category 2C2)

CO_2 and CH_4 are emitted from the production of several ferroalloys. Ferroalloys are composites of iron and other elements such as silicon, manganese, and chromium. When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Estimates from two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon), silicon metal (about 98 percent silicon), and miscellaneous alloys (36 to 65 percent silicon) have been calculated. Emissions from the production of ferrochromium and ferromanganese are not included here because of the small number of manufacturers of these materials in the United States. Subsequently, government information disclosure rules prevent the publication of production data for these production facilities.

Similar to emissions from the production of iron and steel, CO_2 is emitted when metallurgical coke is oxidized during a high-temperature reaction with iron and the selected alloying element. Due to the strong reducing environment, CO is initially produced, and eventually oxidized to CO_2. A representative reaction equation for the production of 50 percent ferrosilicon is given below:

$$Fe_2O_3 + 2SiO_2 + 7C \rightarrow 2FeSi + 7CO$$

While most of the C contained in the process materials is released to the atmosphere as CO_2, a percentage is also released as CH_4 and other volatiles. The amount of CH_4 that is released is dependent on furnace efficiency, operation technique, and control technology.

Emissions of CO_2 from ferroalloy production in 2009 were 1.5 Tg CO_2 Eq. (1,469 Gg) (see Table 4-63 and Table 4-64), which is a 32 percent reduction since 1990. Emissions of CH_4 from ferroalloy production in 2009 were 0.01 Tg CO_2 Eq. (0.406 Gg), which is a 40 percent decrease since 1990.

Table 4-63: CO_2 and CH_4 Emissions from Ferroalloy Production (Tg CO_2 Eq.)

Year	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2.2		1.9		1.4	1.5	1.6	1.6	1.5
CH_4	+		+		+	+	+	+	+
Total	**2.2**		**1.9**		**1.4**	**1.5**	**1.6**	**1.6**	**1.6**

\+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 4-64: CO_2 and CH_4 Emissions from Ferroalloy Production (Gg)

Year	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	2,152		1,893		1,392	1,505	1,552	1,599	1,469
CH_4	1		1		+	+	+	+	+

Methodology

Emissions of CO_2 and CH_4 from ferroalloy production were calculated by multiplying annual ferroalloy production by material-specific emission factors. Emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were applied to ferroalloy production. For ferrosilicon alloys containing 25 to 55 percent silicon and miscellaneous alloys (including primarily magnesium-ferrosilicon, but also including other silicon alloys) containing 32 to 65 percent silicon, an emission factor for 45 percent silicon was applied for CO_2 (2.5 metric tons CO_2/metric ton of alloy produced) and an emission factor for 65 percent silicon was applied for CH_4 (1 kg CH_4/metric ton of alloy produced). Additionally, for ferrosilicon alloys containing 56 to 95 percent silicon, an emission factor for 75 percent silicon ferrosilicon was applied for both CO_2 and CH_4 (4 metric tons CO_2/metric ton alloy produced and 1 kg CH_4/metric ton of alloy produced, respectively). The emission factors for silicon metal equaled 5 metric tons CO_2/metric ton metal produced and 1.2 kg CH_4/metric ton metal produced. It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke using an electric arc furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other biomass, or graphite C inputs. The amount of petroleum coke consumed in ferroalloy production was calculated assuming that the petroleum coke used is 90 percent C and 10 percent inert material.

Ferroalloy production data for 1990 through 2009 (see Table 4-65) were obtained from the USGS through personal communications with the USGS Silicon Commodity Specialist (Corathers 2011) and through the *Minerals Yearbook: Silicon Annual Report* (USGS 1991 through 2010). Because USGS does not provide estimates of silicon metal production for 2006-2009, 2005 production data are used. Until 1999, the USGS reported production of ferrosilicon containing 25 to 55 percent silicon separately from production of miscellaneous alloys containing 32 to 65 percent silicon; beginning in 1999, the USGS reported these as a single category (see Table 4-65). The composition data for petroleum coke was obtained from Onder and Bagdoyan (1993).

Table 4-65: Production of Ferroalloys (Metric Tons)

Year	**Ferrosilicon 25%-55%**	**Ferrosilicon 56%-95%**	**Silicon Metal**	**Misc. Alloys 32-65%**
1990	321,385	109,566	145,744	72,442
2000	229,000	100,000	184,000	NA
2005	123,000	86,100	148,000	NA
2006	164,000	88,700	148,000	NA
2007	180,000	90,600	148,000	NA
2008	193,000	94,000	148,000	NA
2009	123,932	104,855	148,000	NA

NA (Not Available)

Uncertainty and Time-Series Consistency

Although some ferroalloys may be produced using wood or other biomass as a C source, information and data regarding these practices were not available. Emissions from ferroalloys produced with wood or other biomass would not be counted under this source because wood-based C is of biogenic origin.[115] Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO_2 per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available.

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[115] Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Emissions of CH_4 from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH_4 emissions; however, specific furnace information was not available or included in the CH_4 emission estimates.

Also, annual ferroalloy production is now reported by the USGS in three broad categories: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal. It was assumed that the IPCC emission factors apply to all of the ferroalloy production processes, including miscellaneous alloys. Finally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by the USGS to avoid disclosing company proprietary data. Emissions from this production category, therefore, were not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-66. Ferroalloy production CO_2 emissions were estimated to be between 1.3 and 1.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.5 Tg CO_2 Eq. Ferroalloy production CH_4 emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 Tg CO_2 Eq.

Table 4-66: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ferroalloy Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Ferroalloy Production	CO_2	1.5	1.3	1.7	-12%	+13%
Ferroalloy Production	CH_4	+	+	+	-12%	+12%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 Tg CO_2 Eq.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the ferroalloy production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ferroalloy production. Beginning in 2010, all U.S. ferroalloy producing facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. ferroalloy industry, in particular, including emission estimates from production of ferroalloys other than ferrosilicon and silicon metal. If data are available, emissions will be estimated for those ferroalloys. Additionally, research will be conducted to determine whether data are available concerning raw material consumption (e.g., coal coke, limestone and dolomite flux, etc.) for inclusion in ferroalloy production emission estimates.

4.15. Aluminum Production (IPCC Source Category 2C3)

Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured products, including aircraft, automobiles, bicycles, and kitchen utensils. As of last reporting, the United States was the fourth largest producer of primary aluminum, with approximately seven percent of the world total (USGS 2009a). The United States was also a major importer of primary aluminum. The production of primary aluminum—in addition to consuming large quantities of electricity—results in process-related emissions of CO_2 and two perfluorocarbons (PFCs): perfluoromethane (CF_4) and perfluoroethane (C_2F_6).

CO_2 is emitted during the aluminum smelting process when alumina (aluminum oxide, Al_2O_3) is reduced to aluminum using the Hall-Heroult reduction process. The reduction of the alumina occurs through electrolysis in a molten bath of natural or synthetic cryolite (Na_3AlF_6). The reduction cells contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a carbon mass of paste, coke briquettes, or prebaked carbon blocks from petroleum coke. During reduction, most of this carbon is oxidized and released to the atmosphere as CO_2.

Process emissions of CO_2 from aluminum production were estimated to be 3.0 Tg CO_2 Eq. (3,009 Gg) in 2009 (see Table 4-67). The carbon anodes consumed during aluminum production consist of petroleum coke and, to a minor extent, coal tar pitch. The petroleum coke portion of the total CO_2 process emissions from aluminum production is considered to be a non-energy use of petroleum coke, and is accounted for here and not under the CO_2 from Fossil Fuel Combustion source category of the Energy sector. Similarly, the coal tar pitch portion of these CO_2 process emissions is accounted for here.

Table 4-67: CO_2 Emissions from Aluminum Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	6.8	6,831
2000	6.1	6,086
2005	4.1	4,142
2006	3.8	3,801
2007	4.3	4,251
2008	4.5	4,477
2009	3.0	3,009

In addition to CO_2 emissions, the aluminum production industry is also a source of PFC emissions. During the smelting process, when the alumina ore content of the electrolytic bath falls below critical levels required for electrolysis, rapid voltage increases occur, which are termed "anode effects." These anode effects cause carbon from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing fugitive emissions of CF_4 and C_2F_6. In general, the magnitude of emissions for a given smelter and level of production depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects increase, emissions increase.

Since 1990, emissions of CF_4 and C_2F_6 have declined by 92 percent and 89 percent, respectively, to 1.3 Tg CO_2 Eq. of CF_4 (0.20 Gg) and 0.30 Tg CO_2 Eq. of C_2F_6 (0.032 Gg) in 2009, as shown in Table 4-68 and Table 4-69. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects. Since 1990, aluminum production has declined by 57 percent, while the combined CF_4 and C_2F_6 emission rate (per metric ton of aluminum produced) has been reduced by 80 percent.

Table 4-68: PFC Emissions from Aluminum Production (Tg CO_2 Eq.)

Year	CF_4	C_2F_6	Total
1990	15.9	2.7	18.5
2000	7.8	0.8	8.6
2005	2.5	0.4	3.0
2006	2.1	0.4	2.5
2007	3.2	0.6	3.8
2008	2.2	0.5	2.7
2009	1.3	0.3	1.6

Note: Totals may not sum due to independent rounding.

Table 4-69: PFC Emissions from Aluminum Production (Gg)

Year	CF_4	C_2F_6
1990	2.4	0.3
2000	1.2	0.1
2005	0.4	+

2006	0.3	+
2007	0.5	0.1
2008	0.3	0.1
2009	0.2	+

+ Does not exceed 0.05 Gg.

In 2009, U.S. primary aluminum production totaled approximately 1.7 million metric tons, a 35 percent decrease from 2008 production levels (USAA 2010). In 2009, six companies managed production at 13 operational primary aluminum smelters. Four smelters were closed the entire year, and demolition of one smelter that had been idle since 2000 was completed in 2009. Of the operating smelters, three were temporarily idled during some fraction of 2009, and parts of four others were temporarily closed in 2009 (USGS 2010a). During 2009, U.S. primary aluminum production was less for every month when compared to the corresponding month in 2008 (USGS 2009b, USGS 2010b).

For 2010, total production during January through September was approximately 1.28 million metric tons, compared to 1.32 million metric tons for the same period in 2009, only a 3 percent decrease (USGS 2010c). Based on the similarity in production, process CO_2 and PFC emissions are likely to be similar over this period in 2009 given no significant changes in process controls at operational facilities.

Methodology

CO_2 emissions released during aluminum production were estimated by combining individual partner reported data with process-specific emissions modeling. These estimates are based on information gathered by EPA's Voluntary Aluminum Industrial Partnership (VAIP) program.

Most of the CO_2 emissions released during aluminum production occur during the electrolysis reaction of the carbon anode, as described by the following reaction:

$$2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2$$

For prebake smelter technologies, CO_2 is also emitted during the anode baking process. These emissions can account for approximately 10 percent of total process CO_2 emissions from prebake smelters.

Depending on the availability of smelter-specific data, the CO_2 emitted from electrolysis at each smelter was estimated from: (1) the smelter's annual anode consumption, (2) the smelter's annual aluminum production and rate of anode consumption (per ton of aluminum produced) for previous and /or following years, or, (3) the smelter's annual aluminum production and IPCC default CO_2 emission factors. The first approach tracks the consumption and C content of the anode, assuming that all C in the anode is converted to CO_2. Sulfur, ash, and other impurities in the anode are subtracted from the anode consumption to arrive at total C consumption. This approach corresponds to either the IPCC Tier 2 or Tier 3 method, depending on whether smelter-specific data on anode impurities are used. The second approach interpolates smelter-specific anode consumption rates to estimate emissions during years for which anode consumption data are not available. This avoids substantial errors and discontinuities that could be introduced by reverting to Tier 1 methods for those years. The last approach corresponds to the IPCC Tier 1 method (2006) and is used in the absence of present or historic anode consumption data.

The equations used to estimate CO_2 emissions in the Tier 2 and 3 methods vary depending on smelter type (IPCC 2006). For Prebake cells, the process formula accounts for various parameters, including net anode consumption, and the sulfur, ash, and impurity content of the baked anode. For anode baking emissions, the formula accounts for packing coke consumption, the sulfur and ash content of the packing coke, as well as the pitch content and weight of baked anodes produced. For Søderberg cells, the process formula accounts for the weight of paste consumed per metric ton of aluminum produced, and pitch properties, including sulfur, hydrogen, and ash content.

Through the VAIP, anode consumption (and some anode impurity) data have been reported for 1990, 2000, 2003, 2004, 2005, 2006, 2007, 2008, and 2009. Where available, smelter-specific process data reported under the VAIP were used; however, if the data were incomplete or unavailable, information was supplemented using industry average values recommended by IPCC (2006). Smelter-specific CO_2 process data were provided by 18 of the 23 operating smelters in 1990 and 2000, by 14 out of 16 operating smelters in 2003 and 2004, 14 out of 15 operating smelters in 2005, 13 out of 14 operating smelters in 2006, 5 out of 14 operating smelters in, 2007 and 2008, and 3 out of 13 operating smelters in 2009. For years where CO_2 process data were not reported by these companies, estimates were developed through linear interpolation, and/or assuming industry default values.

In the absence of any previous smelter specific process data (i.e., 1 out of 13 smelters in 2009, 1 out of 14 smelters in 2006, 2007, and 2008, 1 out of 15 smelters in 2005, and 5 out of 23 smelters between 1990 and 2003), CO_2 emission estimates were estimated using Tier 1 Søderberg and/or Prebake emission factors (metric ton of CO_2 per metric ton of aluminum produced) from IPCC (2006).

Aluminum production data for 10 out of 13 operating smelters were reported under the VAIP in 2009. Between 1990 and 2008, production data were provided by 21 of the 23 U.S. smelters that operated during at least part of that period. For the non-reporting smelters, production was estimated based on the difference between reporting smelters and national aluminum production levels (USAA 2010), with allocation to specific smelters based on reported production capacities (USGS 2009a).

PFC emissions from aluminum production were estimated using a per-unit production emission factor that is expressed as a function of operating parameters (anode effect frequency and duration), as follows:

$$\text{PFC } (CF_4 \text{ or } C_2F_6) \text{ kg/metric ton Al} = S \times (\text{Anode Effect Minutes/Cell-Day})$$

where,

S = Slope coefficient ((kg PFC/metric ton Al)/(Anode Effect Minutes/Cell-Day))
Anode Effect Minutes/Cell-Day = Anode Effect Frequency/Cell-Day × Anode Effect Duration (minutes)

This approach corresponds to either the Tier 3 or the Tier 2 approach in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), depending upon whether the slope-coefficient is smelter-specific (Tier 3) or technology-specific (Tier 2). For 1990 through 2009, smelter-specific slope coefficients were available and were used for smelters representing between 30 and 94 percent of U.S. primary aluminum production. The percentage changed from year to year as some smelters closed or changed hands and as the production at remaining smelters fluctuated. For smelters that did not report smelter-specific slope coefficients, IPCC technology-specific slope coefficients were applied (IPCC 2000, 2006). The slope coefficients were combined with smelter-specific anode effect data collected by aluminum companies and reported under the VAIP, to estimate emission factors over time. For 1990 through 2009, smelter-specific anode effect data were available for smelters representing between 80 and 100 percent of U.S. primary aluminum production. Where smelter-specific anode effect data were not available, industry averages were used.

For all smelters, emission factors were multiplied by annual production to estimate annual emissions at the smelter level. For 1990 through 2009, smelter-specific production data were available for smelters representing between 30 and 100 percent of U.S. primary aluminum production. (For the years after 2000, this percentage was near the high end of the range.) Production at non-reporting smelters was estimated by calculating the difference between the production reported under VAIP and the total U.S. production supplied by USGS or USAA and then allocating this difference to non-reporting smelters in proportion to their production capacity. Emissions were then aggregated across smelters to estimate national emissions.

National primary aluminum production data for 2009 were obtained via the United States Aluminum Association (USAA 2010). For 1990 through 2001, and 2006 (see Table 4-70) data were obtained from USGS, Mineral Industry Surveys: Aluminum Annual Report (USGS 1995, 1998, 2000, 2001, 2002, 2007). For 2002 through 2005, and 2007 through 2008 national aluminum production data were obtained from the USAA's Primary Aluminum Statistics (USAA 2004, 2005, 2006, 2008, 2009).

Table 4-70: Production of Primary Aluminum (Gg)

Year	Gg
1990	4,048
2000	3,668
2005	2,478
2006	2,284
2007	2,560
2008	2,659
2009	1,727

Uncertainty and Time Series Consistency

The overall uncertainties associated with the 2009 CO_2, CF_4, and C_2F_6 emission estimates were calculated using Approach 2, as defined by IPCC (2006). For CO_2, uncertainty was assigned to each of the parameters used to estimate CO_2 emissions. Uncertainty surrounding reported production data was assumed to be 1 percent (IPCC 2006). For additional variables, such as net C consumption, and sulfur and ash content in baked anodes, estimates for uncertainties associated with reported and default data were obtained from IPCC (2006). A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO_2 emission estimate for the U.S. aluminum industry as a whole, and the results are provided below.

To estimate the uncertainty associated with emissions of CF_4 and C_2F_6, the uncertainties associated with three variables were estimated for each smelter: (1) the quantity of aluminum produced, (2) the anode effect minutes per cell day (which may be reported directly or calculated as the product of anode effect frequency and anode effect duration), and, (3) the smelter- or technology-specific slope coefficient. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emission estimate for each smelter and for the U.S. aluminum industry as a whole.

The results of this quantitative uncertainty analysis are summarized in Table 4-71. Aluminum production-related CO_2 emissions were estimated to be between 2.90 and 3.12 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below to 4 percent above the emission estimate of 3.01 Tg CO_2 Eq. Also, production-related CF_4 emissions were estimated to be between 1.14 and 1.44 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below to 12 percent above the emission estimate of 1.29 Tg CO_2 Eq. Finally, aluminum production-related C_2F_6 emissions were estimated to be between 0.25 and 0.35 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below to 19 percent above the emission estimate of 0.30 Tg CO_2 Eq.

Table 4-71: Tier 2 Quantitative Uncertainty Estimates for CO_2 and PFC Emissions from Aluminum Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to 2009 Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Aluminum Production	CO_2	3.0	2.9	3.1	−4%	+4%
Aluminum Production	CF_4	1.3	1.1	1.4	−12%	+12%
Aluminum Production	C_2F_6	0.3	0.2	0.4	−17%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

The 2009 emission estimate was developed using either company-wide or site-specific PFC slope coefficients for all but 1 of the 14 operating smelters where default IPCC (2006) slope data was used. In some cases, where smelters are owned by one company, data have been reported on a company-wide basis as totals or weighted averages. Consequently, in the Monte Carlo analysis, uncertainties in anode effect minutes per cell-day, slope coefficients, and aluminum production have been applied to the company as a whole and not to each smelter. This probably overestimates the uncertainty associated with the cumulative emissions from these smelters, because errors that were in fact independent were treated as if they were correlated. It is therefore likely that the uncertainties calculated above for the total U.S. 2009 emission estimates for CF_4 and C_2F_6 are also overestimated.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all primary U.S. aluminum producing facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. primary aluminum production industry.

4.16. Magnesium Production and Processing (IPCC Source Category 2C4)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF_6) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. Sulfur hexafluoride has been used in this application around the world for more than twenty-five years. A dilute gaseous mixture of SF_6 with dry air and/or CO_2 is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF_6 reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF_6 reacting in magnesium production and processing is considered to be negligible, and thus all SF_6 used is assumed to be emitted into the atmosphere. Although alternative cover gases, such as AM-cover™ (containing HFC-134a), Novec™ 612 and dilute SO_2 systems can be used, many facilities in the United States are still using traditional SF_6 cover gas systems.

The magnesium industry emitted 1.1 Tg CO_2 Eq. (0.04 Gg) of SF_6 in 2009, representing a decrease of approximately 45 percent from 2008 emissions (See Table 4-72). The decrease can be attributed to die casting facilities in the United States closing or halting production due to reduced demand from the American auto industry and other industrial sectors (USGS 2010a). Production associated with primary and secondary facilities also dropped in 2009. The significant reduction in emissions can also be attributed to industry efforts to switch to cover gas alternatives, such as sulfur dioxide, as part of the EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry.

Table 4-72: SF_6 Emissions from Magnesium Production and Processing (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	5.4	0.2
2000	3.0	0.1
2005	2.9	0.1
2006	2.9	0.1
2007	2.6	0.1
2008	1.9	0.1
2009	1.1	0.04

Methodology

Emission estimates for the magnesium industry incorporate information provided by industry participants in EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry. The Partnership started in 1999 and, currently, participating companies represent 100 percent of U.S. primary and secondary production and 90 percent of the casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). Absolute emissions for 1999 through 2009 from primary production, secondary production (i.e., recycling), and die casting were generally reported by Partnership participants. Partners reported their SF_6 consumption, which was assumed to be equivalent to emissions. When a partner did not report emissions, they were estimated based on the metal processed and emission rate reported by that partner in previous and (if available) subsequent years. Where data for subsequent years was not available, metal production and emissions rates were extrapolated based on the trend shown by partners reporting in the current and previous years. When it was determined a Partner is no longer in production, their metal production and emissions rates were set to zero if no activity information was available; in one case a partner that closed mid-year was estimated to have produced 50 percent of the metal from the prior year.

Emission factors for 2002 to 2006 for sand casting activities were also acquired through the Partnership. For 2007, 2008 and 2009, the sand casting partner did not report and the reported emission factor from 2005 was utilized as being representative of the industry. The 1999 through 2009 emissions from casting operations (other than die) were estimated by multiplying emission factors (kg SF_6 per metric ton of metal produced or processed) by the amount of metal produced or consumed. The emission factors for casting activities are provided below in Table 4-73. The emission factors for primary production, secondary production and sand casting are withheld to protect company-specific production information. However, the emission factor for primary production has not risen above the average 1995 partner value of 1.1 kg SF_6 per metric ton. The emission factors for the other industry sectors (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives. U.S. magnesium consumption (casting) data from 1990 through 2009 were available from the USGS (USGS 2002, 2003, 2005, 2006, 2007, 2008, 2010).

Table 4-73: SF_6 Emission Factors (kg SF_6 per metric ton of magnesium)

Year	Die Casting	Permanent Mold	Wrought	Anodes
1999	2.14[a]	2	1	1
2000	0.72	2	1	1
2001	0.72	2	1	1
2002	0.71	2	1	1
2003	0.81	2	1	1
2004	0.81	2	1	1
2005	0.79	2	1	1
2006	0.86	2	1	1
2007	0.67	2	1	1
2008	1.15[b]	2	1	1
2009	1.77[b]	2	1	1

[a] This is a weighted average that includes an estimated emission factor of 5.2 kg SF_6 per metric ton of magnesium for die casters that did not participate in the Partnership in 1999. These die casters were assumed to be similar to partners that cast small parts. Due to process requirements, these casters consume larger quantities of SF_6 per metric ton of processed magnesium than casters that process large parts. In later years, die casters participating in the Partnership accounted for all U.S. die casting tracked by USGS.

[b] The emission factor for die casting increased significantly between 2007 and 2008, and again between 2008 and 2009. These increases occurred for two reasons. First, one of the die casters with a significant share of U.S. production that had used SF_6 as a cover gas and that had maintained a relatively low emission rate began using an alternative cover gas in 2008. Since the SF_6 emission factor provided here is based only on die casting operations that use SF_6 as a cover gas, the removal of the low-emitting die caster from the SF_6-using group increased the weighted average emission rate of that group. Second, one SF_6-using die caster experienced a significant leak in its cover gas distribution system in 2009 that resulted in an abnormally high SF_6 emission rate.

To estimate emissions for 1990 through 1998, industry emission factors were multiplied by the corresponding metal production and consumption (casting) statistics from USGS. The primary production emission factors were 1.2 kg per metric ton for 1990 through 1993, and 1.1 kg per metric ton for 1994 through 1997. These factors were based on information provided by U.S. primary producers. For die casting, an emission factor of 4.1 kg per metric ton was used for the period 1990 through 1996. This factor was drawn from an international survey of die casters (Gjestland & Magers 1996). For 1996 through 1998, the emission factors for primary production and die casting were assumed to decline linearly to the level estimated based on partner reports in 1999. This assumption is consistent with the trend in SF_6 sales to the magnesium sector that is reported in the RAND survey of major SF_6 manufacturers, which shows a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 2002 through 2009 were provided by the Magnesium Partnership participants, and 1990 through 2001 emission factors for this process were assumed to have been the same as the 2002 emission factor. The emission factor for secondary production from 1990 through 1998 was assumed to be constant at the 1999 average partner value. The emission factors for the other processes (i.e., permanent mold, wrought, and anode casting), about which less is known, were assumed to remain constant at levels defined in Table 4-73.

Uncertainty

To estimate the uncertainty surrounding the estimated 2009 SF_6 emissions from magnesium production and processing, the uncertainties associated with three variables were estimated (1) emissions reported by magnesium producers and processors that participate in the Magnesium Partnership, (2) emissions estimated for magnesium producers and processors that participate in the Partnership but did not report this year, and (3) emissions estimated for magnesium producers and processors that do not participate in the Partnership. An uncertainty of 5 percent was assigned to the data reported by each participant in the Partnership. If partners did not report emissions data during the current reporting year, SF_6 emissions data were estimated using available emission factor and production information reported in prior years; the extrapolation was based on the average trend for partners reporting in the current reporting year and the year prior. The uncertainty associated with the SF_6 usage estimate generated from the extrapolated emission factor and production information was estimated to be 30 percent for each year of extrapolation. The lone sand casting partner did not report in the past two reporting years and its activity and emission factor were held constant at 2005 levels due to a reporting anomaly in 2006 because of malfunctions at the facility. The uncertainty associated with the SF_6 usage for the sand casting partner was 52 percent. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF_6 emissions were estimated using production and consumption statistics reported by USGS and estimated process-specific emission factors (see Table 4-73). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with sand casting activities utilized a partner-reported emission factor with an uncertainty of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic assumption that SF_6 neither reacts nor decomposes during use. The melt surface reactions and high temperatures associated with molten magnesium could potentially cause some gas degradation. Recent measurement studies have identified SF_6 cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007). Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium content; however, the extent to which this technique is used in the United States is unknown.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-74. SF_6 emissions associated with magnesium production and processing were estimated to be between 1.01 and 1.10 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 6 percent below to 5 percent above the 2008 emission estimate of 1.05 Tg CO_2 Eq.

Table 4-74: Tier 2 Quantitative Uncertainty Estimates for SF_6 Emissions from Magnesium Production and Processing (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Magnesium Production	SF_6	1.05	1.01	1.10	-4%	+4%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

The uncertainty estimates for 2009 are lower relative to the previous inventory uncertainty estimate for 2008 emissions, which is likely due to the fact that emission estimates for 2009 are based more on actual reported data than emission estimates for 2008 were in the 1990-2008 inventory, with two emission sources using projected (highly uncertain) estimates.

Planned Improvements

Cover gas research conducted by the EPA over the last decade has found that SF_6 used for magnesium melt protection can have degradation rates on the order of 20 percent in die casting applications (Bartos et al. 2007). Current emission estimates assume (per the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006)) that all SF_6 utilized is emitted to the atmosphere. Additional research may lead to a revision of IPCC Guidelines to reflect this phenomenon and until such time, developments in this sector will be monitored for possible application to the inventory methodology. Another issue that will be addressed in future inventories is the likely adoption of alternate cover gases by U.S. magnesium producers and processors. These cover gases, which include AM-cover™ (containing HFC-134a) and Novec™ 612, have lower GWPs than SF_6, and tend to quickly degrade during their exposure to the molten metal. Magnesium producers and processors have already begun using these cover gases for 2006 through 2009 in a limited fashion; because the amounts being used by companies on the whole are low enough that they have a minor effect on the overall emissions from the industry, these emissions are only being monitored and recorded at this time.

4.17. Zinc Production (IPCC Source Category 2C5)

Zinc production in the United States consists of both primary and secondary processes. Primary production in the United States is conducted through the electrolytic process while secondary techniques used in the United States include the electrothermic and Waelz kiln processes as well as a range of other metallurgical, hydrometallurgical, and pyrometallurgical processes. Worldwide primary zinc production also employs a pyrometallurgical process using the Imperial Smelting Furnace process; however, this process is not used in the United States (Sjardin 2003). Of the primary and secondary processes used in the United States, only the electrothermic and Waelz kiln secondary processes result in non-energy CO_2 emissions (Viklund-White 2000).

During the electrothermic zinc production process, roasted zinc concentrate and secondary zinc products enter a sinter feed where they are burned to remove impurities before entering an electric retort furnace. Metallurgical coke added to the electric retort furnace reduces the zinc oxides and produces vaporized zinc, which is then captured in a vacuum condenser. This reduction process produces non-energy CO_2 emissions (Sjardin 2003).

In the Waelz kiln process, EAF dust, which is captured during the recycling of galvanized steel, enters a kiln along with a reducing agent—often metallurgical coke. When kiln temperatures reach approximately 1100–1200°C, zinc fumes are produced, which are combusted with air entering the kiln. This combustion forms zinc oxide, which is collected in a baghouse or electrostatic precipitator, and is then leached to remove chloride and fluoride. Through this process, approximately 0.33 metric ton of zinc is produced for every metric ton of EAF dust treated (Viklund-White 2000).

In 2009, U.S. primary and secondary zinc production was estimated to total 286,000 metric tons (USGS 2010). Since reported activity data for 2009 were not available for all necessary inputs in time for this publication, production values in 2009 were assumed to equal 2008 values in some cases. The resulting emissions of CO_2 from zinc production in 2009 were estimated to be 0.97 Tg CO_2 Eq. (966 Gg) (see Table 4-75). All 2009 CO_2 emissions resulted from secondary zinc production.

Table 4-75: CO_2 Emissions from Zinc Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	0.7	667
2000	1.0	997
2005	1.1	1088
2006	1.1	1088
2007	1.1	1081
2008	1.2	1230
2009	1.0	966

Emissions from zinc production in the U.S. have increased overall due to a gradual shift from non-emissive primary production to emissive secondary production. In 2009, emissions were estimated to be 45 percent higher than they were in 1990.

Methodology

Non-energy CO_2 emissions from zinc production result from the electrothermic and Waelz kiln secondary production processes, which both use metallurgical coke or other C-based materials as reductants. Sjardin (2003) provides an emission factor of 0.43 metric tons CO_2/metric ton zinc produced for emissive zinc production processes; however, this emission factor is based on the Imperial Smelting Furnace production process. Because the Imperial Smelting Furnace production process is not used in the United States, emission factors specific to electrothermic and Waelz kiln processes were needed. Due to the limited amount of information available for these electrothermic processes, only Waelz kiln process-specific emission factors were developed. These emission factors were applied to both the Waelz kiln and electrothermic secondary zinc production processes.

A Waelz kiln emission factor based on the amount of zinc produced was developed based on the amount of metallurgical coke consumed for non-energy purposes per ton of zinc produced, 1.19 metric tons coke/metric ton zinc produced (Viklund-White 2000), and the following equation:

$$EF_{\text{Waelz Kiln}} = \frac{1.19\ metric\ tons\ coke}{metric\ tons\ zinc} \times \frac{0.85\ metric\ tons\ C}{metric\ tons\ coke} \times \frac{3.67\ metric\ tons\ CO_2}{metric\ tons\ C} = \frac{3.70\ metric\ tons\ CO_2}{metric\ tons\ zinc}$$

In addition, a Waelz kiln emission factor based on the amount of EAF dust consumed was developed based on the amount of metallurgical coke consumed per ton of EAF dust consumed, 0.4 metric tons coke/metric ton EAF dust consumed (Viklund-White 2000), and the following equation:[116]

$$EF_{\text{EAF Dust}} = \frac{0.4\ metric\ tons\ coke}{metric\ tons\ EAF\ dust} \times \frac{0.85\ metric\ tons\ C}{metric\ tons\ coke} \times \frac{3.67\ metric\ tons\ CO_2}{metric\ tons\ C} = \frac{1.24\ metric\ tons\ CO_2}{metric\ tons\ EAF\ Dust}$$

The only companies in the United States that use emissive technology to produce secondary zinc products are Horsehead Corp and Steel Dust Recycling. For Horsehead Corp, EAF dust is recycled in Waelz kilns at their Beaumont, TX; Calumet, IL; Palmerton, PA; and Rockwood, TN facilities (and soon to be performed at their new South Carolina facility). These Waelz kiln facilities produce intermediate zinc products (crude zinc oxide or calcine), most of which is transported to their Monaca, PA facility where the products are smelted into refined zinc using electrothermic technology. Some of Horsehead's intermediate zinc products that are not smelted at Monaca are instead exported to other countries around the world (Horsehead Corp 2010). Steel Dust Recycling recycles EAF dust into intermediate zinc products using Waelz kilns, and then sells the intermediate products to companies who smelt it into refined products.

The total amount of EAF dust consumed by Horsehead Corp at their Waelz kilns was available from Horsehead financial reports for years 2006 through 2009 (Horsehead 2010). Consumption levels for 1990 through 2005 were extrapolated using the percentage change in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The EAF dust consumption values for each year were then multiplied by the 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor to develop CO_2 emission estimates for Horsehead's Waelz kiln facilities.

The amount of EAF dust consumed by the Steel Dust Recycling facility for 2008 and 2009 (the only two years it has been in operation) was not publically available. Therefore, these consumption values were estimated by calculating the 2008 and 2009 capacity utilization of Horsehead's Waelz kilns and multiplying this utilization ratio by the capacity of Steel Dust Recycling's facility, which were available from the company (Steel Dust Recycling LLC 2010). The 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor was then applied to Steel Dust Recycling's estimated EAF dust consumption to develop CO_2 emission estimates for its Waelz kiln facility.

Refined zinc production levels for Horsehead's Monaca, PA facility (utilizing electrothermic technology) were available from the company for years 2005 through 2009 (Horsehead Corp 2010, Horsehead Corp 2008). Production levels for 1990 through 2004 were extrapolated using the percentage changes in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The 3.70 metric tons CO_2/metric ton zinc emission factor was then applied to the Monaca facility's production levels to estimate CO_2 emissions for the facility. The Waelz kiln production emission factor was applied in this case rather than the EAF dust consumption emission factor since Horsehead's Monaca facility did not consume EAF dust.

Table 4-76: Zinc Production (Metric Tons)

Year	Primary	Secondary
1990	262,704	95,708
2000	227,800	143,000
2005	191,120	156,000
2006	113,000	156,000
2007	121,000	157,000
2008	125,000	161,000
2009	125,000	161,000

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[116] For Waelz kiln based secondary zinc production, IPCC recommends the use of emission factors based on EAF dust consumption rather than the amount of zinc produced since the amount of reduction materials used is more directly dependent on the amount of EAF dust consumed (IPCC 2006).

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are two-fold, relating to activity data and emission factors used.

First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in Waelz kilns is based on (1) an EAF dust consumption value reported annually by Horsehead Corporation as part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an estimate of the amount of EAF dust consumed at a Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust consumption information is not available for the Steel Dust Recycling LLC facility, the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the company's Web site) by the capacity utilization factor for Horsehead Corporation (which is available from Horsehead's financial reports). Therefore, there is uncertainty associated with the assumption that the capacity utilization of Steel Dust Recycling LLC's Waelz kiln facility is equal to the capacity utilization of Horsehead's Waelz kiln facility. Second, there are uncertainties associated with the emission factors used to estimate CO_2 emissions from secondary zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors depend upon the accuracy of these materials balances. Data limitations prevented the development of emission factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both electrothermic and Waelz kiln production processes. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-77. Zinc production CO_2 emissions were estimated to be between 0.8 and 1.1 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below and 18 percent above the emission estimate of 1.0 Tg CO_2 Eq.

Table 4-77: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Zinc Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] **(Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Zinc Production	CO_2	1.0	0.8	1.1	-17%	+18%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the zinc production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from zinc production. Beginning in 2010, all U.S. zinc producing facilities (both primary and secondary) that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. zinc production industry.

Recalculations Discussion

The methodology for estimating CO_2 emissions from zinc production was revised for the current Inventory based on the availability of new data regarding secondary zinc production in the United States. The previous Inventory methodology assumed that two facilities had produced zinc in the United States using emissive processes since 1990: Horsehead Corporation's Monaca, PA facility (electrothermic) and Horsehead Corporation's Palmerton, PA facility (Waelz kiln). The 3.70 metric tons CO_2/metric ton zinc emission factor was applied to the estimated refined zinc production at the Monaca, PA electrothermic facility, and the 1.24 metric tons CO_2/metric ton EAF dust consumed emission factor was applied to the estimated EAF dust consumption at the Palmerton, PA Waelz kiln facility. The annual zinc production (for the Monaca facility) and EAF dust consumption (for the Palmerton facility) were estimated using historic values that were published in articles for select years (extrapolation techniques were used for years in which published data was not available). The Monaca, PA facility was assumed to have closed in 2003 and not operated since.

New data for the industry showed that there were emissive zinc-producing facilities not being captured by the previous Inventory methodology. The facilities that were not captured included three Horsehead Corp Waelz kiln facilities in Beaumont, TX; Calumet, IL; and Rockwood, TN as well as a Waelz kiln facility commissioned in 2008 in Millport, AL by Steel Dust Recycling LLC. Also, research showed that the Monaca, PA facility only closed temporarily in 2003 and has been operating every year since (the Monaca, PA facility produces refined zinc from intermediary zinc products produced at Horsehead's other facilities). The updated methodology utilizes EAF dust consumption values and secondary zinc production values released annually by the main secondary zinc producer in the United States (Horsehead Corp.), and also includes the previously overlooked secondary zinc producing facilities in the emission estimates.

As a result of the revised methodology, historical emission estimates decreased by an average of 11 percent between 1990 and 2002, while emission estimates increased by an average of 140 percent between 2003 and 2009. The significant changes in emission estimates for years 2005 through 2008 were largely driven by Horsehead Corp's Monaca, PA facility being captured in the emission calculations for these years.

4.18. Lead Production (IPCC Source Category 2C5)

Lead production in the United States consists of both primary and secondary processes—both of which emit CO_2 (Sjardin 2003). Primary lead production, in the form of direct smelting, occurs at a just a single plant in Missouri. Secondary production largely involves the recycling of lead acid batteries at approximately 21 separate smelters in the United States. Fifteen of those secondary smelters have annual capacities of 15,000 tons or more and were collectively responsible for 99 percent of secondary lead production in 2009 (USGS 2010). Secondary lead production has increased in the United States over the past decade while primary lead production has decreased. In 2009, secondary lead production accounted for approximately 92 percent of total lead production (USGS 2011).

Primary production of lead through the direct smelting of lead concentrate produces CO_2 emissions as the lead concentrates are reduced in a furnace using metallurgical coke (Sjardin 2003). U.S. primary lead production decreased by 24 percent from 2008 to 2009, and has decreased by 75 percent since 1990 (USGS 2011, USGS 1995).

Similar to primary lead production, CO_2 emissions from secondary production result when a reducing agent, usually metallurgical coke, is added to the smelter to aid in the reduction process. CO_2 emissions from secondary production also occur through the treatment of secondary raw materials (Sjardin 2003). U.S. secondary lead production decreased from 2008 to 2009 by 3 percent, and has increased by 20 percent since 1990 (USGS 2011, USGS 1995).

At last reporting, the United States was the third largest mine producer of lead in the world, behind China and Australia, accounting for 11 percent of world production in 2009 (USGS 2011). In 2009, U.S. primary and secondary lead production totaled 1,213,000 metric tons (USGS 2011). The resulting emissions of CO_2 from 2009 production were estimated to be 0.5 Tg CO_2 Eq. (525 Gg) (see Table 4-78). The majority of 2009 lead production is from secondary processes, which accounted for 95 percent of total 2009 CO_2 emissions.

Table 4-78: CO_2 Emissions from Lead Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	0.5	516
2000	0.6	594
2005	0.6	553
2006	0.6	560
2007	0.6	562
2008	0.6	551
2009	0.5	525

After a gradual decrease in total emissions from 1990 to 1995, total emissions have gradually increased since 1995 and emissions in 2009 were two percent greater than in 1990. Although primary production has decreased significantly (75 percent since 1990), secondary production has increased by about 20 percent over the same time period. Since secondary production is more emissions-intensive, the increase in secondary production since 1990 has resulted in a net increase in emissions despite the sharp decrease in primary production (USGS 2011, USGS 1994).

Methodology

Non-energy CO_2 emissions from lead production result from primary and secondary production processes that use metallurgical coke or other C-based materials as reductants. For primary lead production using direct smelting, Sjardin (2003) and the IPCC (2006) provide an emission factor of 0.25 metric tons CO_2/metric ton lead. For secondary lead production, Sjardin (2003) and IPCC (2006) provide an emission factor of 0.25 metric tons CO_2/metric ton lead for direct smelting as well as an emission factor of 0.2 metric tons CO_2/metric ton lead produced for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). The direct smelting factor (0.25) and the sum of the direct smelting and pretreatment emission factors (0.45) are multiplied by total U.S. primary and secondary lead production, respectively, to estimate CO_2 emissions.

The 1990 through 2009 activity data for primary and secondary lead production (see Table 4-79) were obtained through the USGS Mineral Yearbook: Lead (USGS 1994 through 2011).

Table 4-79: Lead Production (Metric Tons)

Year	Primary	Secondary
1990	404,000	922,000
2000	341,000	1,130,000
2005	143,000	1,150,000
2006	153,000	1,160,000
2007	123,000	1,180,000
2008	135,000	1,150,000
2009	103,000	1,110,000

Uncertainty and Time-Series Consistency

Uncertainty associated with lead production relates to the emission factors and activity data used. The direct smelting emission factor used in primary production is taken from Sjardin (2003) who averages the values provided by three other studies (Dutrizac et al. 2000, Morris et al. 1983, Ullman 1997). For secondary production, Sjardin (2003) adds a CO_2 emission factor associated with battery treatment. The applicability of these emission factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the accuracy of primary and secondary production data provided by the USGS.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-80. Lead production CO_2 emissions were estimated to be between 0.5 and 0.6 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 14 percent below and 15 percent above the emission estimate of 0.5 Tg CO_2 Eq.

Table 4-80: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lead Production (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lead Production	CO_2	0.5	0.5	0.6	-14%	+15%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lead production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emission calculations from lead production. Beginning in 2010, all U.S. lead producing facilities (primary and secondary) that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the Program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. lead production industry.

Recalculations Discussion

In previous Inventory reports, CO_2 emissions from secondary lead production were estimated by multiplying secondary lead production values from USGS by an emission factor of 0.2 metric tons CO_2/metric ton lead produced. This emission factor is provided by Sjardin (2003) and IPCC (2006) for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). Due to a misinterpretation of language in Sjardin (2003) and IPCC (2006), this was the only emission factor applied to secondary lead production even though an emission factor of 0.25 metric tons CO_2/metric ton lead for direct smelting should have been applied as well. This issue has been corrected for the current Inventory, and increased 1990 through 2008 emissions from lead production by an average of 95 percent per year relative to the previous Inventory.

4.19. HCFC-22 Production (IPCC Source Category 2E1)

Trifluoromethane (HFC-23 or CHF_3) is generated as a by-product during the manufacture of chlorodifluoromethane (HCFC-22), which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock for manufacturing synthetic polymers. Between 1990 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons (CFCs) in many applications. Between 2000 and 2007, U.S. production fluctuated but generally remained above 1990 levels. In 2008 and 2009, U.S. production declined markedly. Because HCFC-22 depletes stratospheric ozone, its production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act.[117] Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform ($CHCl_3$) and hydrogen fluoride (HF) in the presence of a catalyst, $SbCl_5$. The reaction of the catalyst and HF produces $SbCl_xF_y$, (where $x + y = 5$), which reacts with chlorinated hydrocarbons to replace chlorine atoms with fluorine. The HF and chloroform are introduced by submerged piping into a continuous-flow reactor that contains the catalyst in a hydrocarbon mixture of chloroform and partially fluorinated intermediates. The vapors leaving the reactor contain HCFC-21 ($CHCl_2F$), HCFC-22 ($CHClF_2$), HFC-23 (CHF_3), HCl, chloroform, and HF. The under-fluorinated intermediates (HCFC-21) and chloroform are then condensed and returned to the reactor, along with residual catalyst, to undergo further fluorination. The final vapors leaving the condenser are primarily HCFC-22, HFC-23, HCl and residual HF. The HCl is recovered as a useful byproduct, and the HF is removed. Once separated from HCFC-22, the HFC-23 may be released to the atmosphere, recaptured for use in a limited number of applications, or destroyed.

Emissions of HFC-23 in 2009 were estimated to be 5.4 Tg CO_2 Eq. (0.5 Gg) (Table 4-81). This quantity represents a 60 percent decrease from 2008 emissions and a 85 percent decline from 1990 emissions. The decrease from 2008 emissions was caused by a 27 percent decrease in HCFC-22 production and a 46 percent decrease in the HFC-23 emission rate. The decline from 1990 emissions is due to a 34 percent decrease in HCFC-22 production and a 78 percent decrease in the HFC-23 emission rate since 1990. The decrease in the emission rate is primarily attributable to five factors: (a) five plants that did not capture and destroy the HFC-23 generated have ceased production of HCFC-22 since 1990, (b) one plant that captures and destroys the HFC-23 generated began to produce HCFC-22, (c) one plant implemented and documented a process change that reduced the amount of HFC-23 generated, and (d) the same plant began recovering HFC-23, primarily for destruction and secondarily for sale, and (e) another plant began destroying HFC-23. All three HCFC-22 production plants operating in the United States in 2009 used thermal oxidation to significantly lower their HFC-23 emissions.

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[117] As construed, interpreted, and applied in the terms and conditions of the *Montreal Protocol on Substances that Deplete the Ozone Layer*. [42 U.S.C. §7671m(b), CAA §614]

Table 4-81: HFC-23 Emissions from HCFC-22 Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	36.4	3
2000	28.6	2
2005	15.8	1
2006	13.8	1
2007	17.0	1
2008	13.6	1
2009	5.4	0.46

Methodology

To estimate HFC-23 emissions for five of the eight HCFC-22 plants that have operated in the United States since 1990, methods comparable to the Tier 3 methods in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were used. For the other three plants, the last of which closed in 1993, methods comparable to the Tier 1 method in the 2006 IPCC Guidelines were used. Emissions from these three plants have been calculated using the recommended emission factor for unoptimized plants operating before 1995 (0.04 kg HCFC-23/kg HCFC-22 produced).

The five plants that have operated since 1994 measured concentrations of HFC-23 to estimate their emissions of HFC-23. Plants using thermal oxidation to abate their HFC-23 emissions monitor the performance of their oxidizers to verify that the HFC-23 is almost completely destroyed. Plants that release (or historically have released) some of their byproduct HFC-23 periodically measure HFC-23 concentrations in the output stream using gas chromatography. This information is combined with information on quantities of products (e.g., HCFC-22) to estimate HFC-23 emissions.

In most years, including 2010, an industry association aggregates and reports to EPA country-level estimates of HCFC-22 production and HFC-23 emissions (ARAP 1997, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010). However, in 1997 and 2008, EPA (through a contractor) performed comprehensive reviews of plant-level estimates of HFC-23 emissions and HCFC-22 production (RTI 1997; RTI 2008). These reviews enabled EPA to review, update, and where necessary, correct U.S. totals, and also to perform plant-level uncertainty analyses (Monte-Carlo simulations) for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production are presented in Table 4-82.

Table 4-82: HCFC-22 Production (Gg)

Year	Gg
1990	139
2000	186
2005	156
2006	154
2007	162
2008	126
2009	91

Uncertainty and Time Series Consistency

The uncertainty analysis presented in this section was based on a plant-level Monte Carlo simulation for 2006. The Monte Carlo analysis used estimates of the uncertainties in the individual variables in each plant's estimating procedure. This analysis was based on the generation of 10,000 random samples of model inputs from the probability density functions for each input. A normal probability density function was assumed for all measurements and biases except the equipment leak estimates for one plant; a log-normal probability density function was used for this plant's equipment leak estimates. The simulation for 2006 yielded a 95-percent confidence interval for U.S. emissions of 6.8 percent below to 9.6 percent above the reported total.

Because plant-level emissions data for 2009 were not available, the relative errors yielded by the Monte Carlo simulation for 2006 were applied to the U.S. emission estimate for 2009. The resulting estimates of absolute uncertainty are likely to be accurate because (1) the methods used by the three plants to estimate their emissions are not believed to have changed significantly since 2006, and (2) although the distribution of emissions among the plants may have changed between 2008 and 2009 (because both HCFC-22 production and the HFC-23 emission rate declined significantly), the two plants that contribute significantly to emissions were estimated to have similar relative uncertainties in their 2006 (as well as 2005) emission estimates. Thus, changes in the relative contributions of these two plants to total emissions are not likely to have a large impact on the uncertainty of the national emission estimate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-83. HFC-23 emissions from HCFC-22 production were estimated to be between 5.0 and 5.9 Tg CO_2 Eq. at the 95percent confidence level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 5.4 Tg CO_2 Eq.

Table 4-83: Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]** (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
HCFC-22 Production	HFC-23	5.4	5.0	5.9	-7%	+10%

[a] Range of emissions reflects a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all U.S. HCFC-22 production facilities are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Data collected under this program will be used in future inventories to improve the calculation of national emissions from HCFC-22 production

4.20. Substitution of Ozone Depleting Substances (IPCC Source Category 2F)

Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are used as alternatives to several classes of ozone-depleting substances (ODSs) that are being phased out under the terms of the Montreal Protocol and the Clean Air Act Amendments of 1990.[118] Ozone depleting substances—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—are used in a variety of industrial applications including refrigeration and air conditioning equipment, solvent cleaning, foam production, sterilization, fire extinguishing, and aerosols. Although HFCs and PFCs are not harmful to the stratospheric ozone layer, they are potent greenhouse gases. Emission estimates for HFCs and PFCs used as substitutes for ODSs are provided in Table 4-84 and Table 4-85.

Table 4-84: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO_2 Eq.)

Gas	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
HFC-23	+	+	+	+	+	+	+
HFC-32	+	+	0.3	0.6	1.0	1.3	1.7
HFC-125	+	5.2	10.1	12.5	15.1	18.2	21.6
HFC-134a	+	60.4	75.1	75.0	72.3	69.3	66.7
HFC-143a	+	4.1	12.2	14.4	16.7	19.2	22.0
HFC-236fa	+	0.5	0.8	0.8	0.9	0.9	0.9

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[118] [42 U.S.C § 7671, CAA § 601]

CF_4	+	+	+	+	+	+	+
Others*	0.3	4.0	5.6	6.0	6.3	6.7	7.0
Total	**0.3**	**74.3**	**104.2**	**109.4**	**112.3**	**115.5**	**120.0**

+ Does not exceed 0.05 Tg CO_2 Eq.

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C_4F_{10}, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications. For estimating purposes, the GWP value used for PFC/PFPEs was based upon C_6F_{14}.

Note: Totals may not sum due to independent rounding.

Table 4-85: Emissions of HFCs and PFCs from ODS Substitution (Mg)

Gas	1990	2000	2005	2006	2007	2008	2009
HFC-23	+	1	1	1	1	2	2
HFC-32	+	26	505	971	1,465	1,977	2,540
HFC-125	+	1,855	3,619	4,453	5,393	6,486	7,730
HFC-134a	+	46,465	57,777	57,728	55,603	53,294	51,281
HFC-143a	+	1,089	3,200	3,782	4,402	5,044	5,798
HFC-236fa	+	85	125	131	136	141	144
CF_4	+	1	2	2	2	2	2
Others*	M	M	M	M	M	M	M

M (Mixture of Gases)

+ Does not exceed 0.5 Mg

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C_4F_{10}, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications.

In 1990 and 1991, the only significant emissions of HFCs and PFCs as substitutes to ODSs were relatively small amounts of HFC-152a—used as an aerosol propellant and also a component of the refrigerant blend R-500 used in chillers—and HFC-134a in refrigeration end-uses. Beginning in 1992, HFC-134a was used in growing amounts as a refrigerant in motor vehicle air-conditioners and in refrigerant blends such as R-404A.[119] In 1993, the use of HFCs in foam production began, and in 1994 these compounds also found applications as solvents. In 1995, ODS substitutes for halons entered widespread use in the United States as halon production was phased-out.

The use and subsequent emissions of HFCs and PFCs as ODS substitutes has been increasing from small amounts in 1990 to 120.0 Tg CO_2 Eq. in 2009. This increase was in large part the result of efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely accelerate over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out under the provisions of the Copenhagen Amendments to the Montreal Protocol. Improvements in the technologies associated with the use of these gases and the introduction of alternative gases and technologies, however, may help to offset this anticipated increase in emissions.

Table 4-86 presents emissions of HFCs and PFCs as ODS substitutes by end-use sector for 1990 through 2009. The end-use sectors that contributed the most toward emissions of HFCs and PFCs as ODS substitutes in 2009 include refrigeration and air-conditioning (104.9 Tg CO_2 Eq., or approximately 87 percent), aerosols (9.1 Tg CO_2 Eq., or approximately 8 percent), and foams (3.9 Tg CO_2 Eq., or approximately 3 percent). Within the refrigeration and air-conditioning end-use sector, motor vehicle air-conditioning was the highest emitting end-use (45.9 Tg CO_2 Eq.), followed by refrigerated retail food and transport. Each of the end-use sectors is described in more detail below.

Table 4-86: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO_2 Eq.) by Sector

Gas	1990	2000	2005	2006	2007	2008	2009
Refrigeration/Air Conditioning	+	61.6	93.1	97.6	99.8	102.3	104.9
Aerosols	0.3	10.1	7.3	7.7	8.2	8.6	9.1
Foams	+	0.3	1.9	2.1	2.3	2.5	3.9
Solvents	+	2.1	1.3	1.3	1.3	1.3	1.3
Fire Protection	+	0.2	0.5	0.6	0.7	0.7	0.8
Total	**0.3**	**74.3**	**104.2**	**109.4**	**112.3**	**115.5**	**120.0**

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[119] R-404A contains HFC-125, HFC-143a, and HFC-134a.

Refrigeration/Air Conditioning

The refrigeration and air-conditioning sector includes a wide variety of equipment types that have historically used CFCs or HCFCs. End-uses within this sector include motor vehicle air-conditioning, retail food refrigeration, refrigerated transport (e.g., ship holds, truck trailers, railway freight cars), household refrigeration, residential and small commercial air-conditioning/and heat pumps, chillers (large comfort cooling), cold storage facilities, and industrial process refrigeration (e.g., systems used in food processing, chemical, petrochemical, pharmaceutical, oil and gas, and metallurgical industries). As the ODS phaseout is taking effect, most equipment is being or will eventually be retrofitted or replaced to use HFC-based substitutes. Common HFCs in use today in refrigeration/air-conditioning equipment are HFC-134a, R-410A[120], R-404A, and R-507A[121]. These HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events.

Aerosols

Aerosol propellants are used in metered dose inhalers (MDIs) and a variety of personal care products and technical/specialty products (e.g., duster sprays and safety horns). Many pharmaceutical companies that produce MDIs—a type of inhaled therapy used to treat asthma and chronic obstructive pulmonary disease—have committed to replace the use of CFCs with HFC-propellant alternatives. The earliest ozone-friendly MDIs were produced with HFC-134a, but the industry has started to use HFC-227ea as well. Conversely, since the use of CFC propellants was banned in 1978, most consumer aerosol products have not transitioned to HFCs, but to “not-in-kind” technologies, such as solid roll-on deodorants and finger-pump sprays. The transition away from ODS in specialty aerosol products has also led to the introduction of non-fluorocarbon alternatives (e.g., hydrocarbon propellants) in certain applications, in addition to HFC-134a or HFC-152a. These propellants are released into the atmosphere as the aerosol products are used.

Foams

CFCs and HCFCs have traditionally been used as foam blowing agents to produce polyurethane (PU), polystyrene, polyolefin, and phenolic foams, which are used in a wide variety of products and applications. Since the Montreal Protocol, flexible PU foams as well as other types of foam, such as polystyrene sheet, polyolefin, and phenolic foam, have transitioned almost completely away from fluorocompounds, into alternatives such as CO_2, methylene chloride, and hydrocarbons. The majority of rigid PU foams have transitioned to HFCs—primarily HFC-134a and HFC-245fa. Today, these HFCs are used to produce polyurethane appliance, PU commercial refrigeration, PU spray, and PU panel foams—used in refrigerators, vending machines, roofing, wall insulation, garage doors, and cold storage applications. In addition, HFC-152a is used to produce polystyrene sheet/board foam, which is used in food packaging and building insulation. Emissions of blowing agents occur when the foam is manufactured as well as during the foam lifetime and at foam disposal, depending on the particular foam type.

Solvents

CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), and to a lesser extent carbon tetrachloride (CCl_4) were historically used as solvents in a wide range of cleaning applications, including precision, electronics, and metal cleaning. Since their phaseout, metal cleaning end-use applications have primarily transitioned to non-fluorocarbon solvents and not-in-kind processes. The precision and electronics cleaning end-uses have transitioned in part to high-GWP gases, due to their high reliability, excellent compatibility, good stability, low toxicity, and selective solvency. These applications rely on HFC-4310mee, HFC-365mfc, HFC-245fa, and to a lesser extent, PFCs. Electronics cleaning involves removing flux residue that remains after a soldering operation for printed circuit boards and other contamination-sensitive electronics applications. Precision cleaning may apply to either electronic components or to metal surfaces, and is characterized by products, such as disk drives, gyroscopes, and optical components, that require a high level of cleanliness and generally have complex shapes, small clearances, and other cleaning

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[120] R-410A contains HFC-32 and HFC-125.

[121] R-507A, also called R-507, contains HFC-125 and HFC-143a.

challenges. The use of solvents yields fugitive emissions of these HFCs and PFCs.

Fire Protection

Fire protection applications include portable fire extinguishers (“streaming” applications) that originally used halon 1211, and total flooding applications that originally used halon 1301, as well as some halon 2402. Since the production and sale of halons were banned in the United States in 1994, the halon replacement agent of choice in the streaming sector has been dry chemical, although HFC-236ea is also used to a limited extent. In the total flooding sector, HFC-227ea has emerged as the primary replacement for halon 1301 in applications that require clean agents. Other HFCs, such as HFC-23, HFC-236fa, and HFC-125, are used in smaller amounts. The majority of HFC-227ea in total flooding systems is used to protect essential electronics, as well as in civil aviation, military mobile weapons systems, oil/gas/other process industries, and merchant shipping. As fire protection equipment is tested or deployed, emissions of these HFCs occur.

Methodology

A detailed Vintaging Model of ODS-containing equipment and products was used to estimate the actual—versus potential—emissions of various ODS substitutes, including HFCs and PFCs. The name of the model refers to the fact that it tracks the use and emissions of various compounds for the annual “vintages” of new equipment that enter service in each end-use. The Vintaging Model predicts ODS and ODS substitute use in the United States based on modeled estimates of the quantity of equipment or products sold each year containing these chemicals and the amount of the chemical required to manufacture and/or maintain equipment and products over time. Emissions for each end-use were estimated by applying annual leak rates and release profiles, which account for the lag in emissions from equipment as they leak over time. By aggregating the data for nearly 60 different end-uses, the model produces estimates of annual use and emissions of each compound. Further information on the Vintaging Model is contained in Annex 3.8.

Uncertainty

Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of point and mobile sources throughout the United States, emission estimates must be made using analytical tools such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales, equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the various compounds.

The Vintaging Model estimates emissions from nearly 60 end-uses. The uncertainty analysis, however, quantifies the level of uncertainty associated with the aggregate emissions resulting from the top 21 end-uses, comprising over 95 percent of the total emissions, and 5 other end-uses. These 26 end-uses comprise 97 percent of the total emissions. In an effort to improve the uncertainty analysis, additional end-uses are added annually, with the intention that over time uncertainty for all emissions from the Vintaging Model will be fully characterized. Any end-uses included in previous years’ uncertainty analysis were included in the current uncertainty analysis, whether or not those end-uses were included in the top 95 percent of emissions from ODS Substitutes.

In order to calculate uncertainty, functional forms were developed to simplify some of the complex “vintaging” aspects of some end-use sectors, especially with respect to refrigeration and air-conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert judgment, and a Monte Carlo analysis was performed. The most significant sources of uncertainty for this source category include the emission factors for retail food equipment and refrigerated transport, as well as the percent of non-MDI aerosol propellant that is HFC-152a.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-87. Substitution of ozone depleting substances HFC and PFC emissions were estimated to be between 111.8 and 129.3 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below to 8 percent above the emission estimate of 120.0 Tg CO_2 Eq.

Table 4-87: Tier 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (Tg CO_2 Eq. and Percent)

Source	Gases	2009 Emission Estimate (Tg CO_2 Eq.)[a]	Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Substitution of Ozone Depleting Substances	HFCs and PFCs	117.1	109.0	126.5	-7%	+8%

[a] 2009 emission estimates and the uncertainty range presented in this table correspond to selected end-uses within the aerosols, foams, solvents, fire extinguishing agents, and refrigerants sectors, but not for other remaining categories. Therefore, because the uncertainty associated with emissions from "other" ODS substitutes was not estimated, they were excluded in the estimates reported in this table.

[b] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Recalculations Discussion

An extensive review of the MDI aerosol, unitary air-conditioning, and domestic refrigerator foams markets resulted in revisions to the Vintaging Model since the previous Inventory. For MDI aerosols, the charge size for both the CFC and HFC propellants was revised. Based on research on substitutes and growth in the market, the percent of the CFC market that transitions to HFCs over the time series and the overall size of the MDI market decreased. For unitary air-conditioning, a review of air conditioner sales data reduced the quantity of air-conditioning equipment introduced into the market for 1990 through1993 and 2008, while increasing the quantity of equipment sold into the market for 1994 through 2009. A review of the domestic refrigerator foams market increased the quantity of blowing agent consumed in the foam and decreased the quantity of blowing agent emitted during the foam manufacturing process. Overall, these changes to the Vintaging Model increased greenhouse gas emissions on average by 0.5 percent across the time series.

4.21. Semiconductor Manufacture (IPCC Source Category 2F6)

The semiconductor industry uses multiple long-lived fluorinated gases in plasma etching and plasma enhanced chemical vapor deposition (PECVD) processes to produce semiconductor products. The gases most commonly employed are trifluoromethane (HFC-23 or CHF_3), perfluoromethane (CF_4), perfluoroethane (C_2F_6), nitrogen trifluoride (NF_3), and sulfur hexafluoride (SF_6), although other compounds such as perfluoropropane (C_3F_8) and perfluorocyclobutane (c-C_4F_8) are also used. The exact combination of compounds is specific to the process employed.

A single 300 mm silicon wafer that yields between 400 to 500 semiconductor products (devices or chips) may require as many as 100 distinct fluorinated-gas-using process steps, principally to deposit and pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as silicon dioxide and silicon nitride, is performed to provide pathways for conducting material to connect individual circuit components in each device. The patterning process uses plasma-generated fluorine atoms, which chemically react with exposed dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated fluorinated gases flow into waste streams and, unless emission abatement systems are employed, into the atmosphere. PECVD chambers, used for depositing dielectric films, are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and, unless abatement systems are employed, into the atmosphere. In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere. For example, when C_2F_6 is used in cleaning or etching, CF_4 is generated and emitted as a process by-product. Besides dielectric film etching and PECVD chamber cleaning, much smaller quantities of fluorinated gases are used to etch polysilicon films and refractory metal films like tungsten.

For 2009, total weighted emissions of all fluorinated greenhouse gases by the U.S. semiconductor industry were estimated to be 5.3 Tg CO_2 Eq. Combined emissions of all fluorinated greenhouse gases are presented in Table 4-88 and Table 4-89 below for years 1990, 2000 and the period 2005 to 2009. The rapid growth of this industry and the increasing complexity (growing number of layers)[122] of semiconductor products led to an increase in emissions of 148 percent between 1990 and 1999, when emissions peaked at 7.2 Tg CO_2 Eq. The emissions growth rate began to slow after 1998, and emissions declined by 26 percent between 1999 and 2009. Together, industrial growth and adoption of emissions reduction technologies, including but not limited to abatement technologies, resulted in a net increase in emissions of 83 percent between 1990 and 2009.

Table 4-88: PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture (Tg CO_2 Eq.)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CF_4	0.7	1.8	1.1	1.2	1.3	1.4	1.5
C_2F_6	1.5	3.0	2.0	2.2	2.3	2.4	2.5
C_3F_8	0.0	0.1	0.0	0.0	0.0	0.1	0.0
C_4F_8	0.0	0.0	0.1	0.1	0.1	0.1	0.0
HFC-23	0.2	0.3	0.2	0.3	0.3	0.3	0.3
SF_6	0.5	1.1	1.0	1.0	0.8	0.9	1.0
NF_3*	0.0	0.2	0.4	0.7	0.5	0.6	0.5
Total	**2.9**	**6.2**	**4.4**	**4.7**	**4.8**	**5.1**	**5.3**

Note: Totals may not sum due to independent rounding.

* NF_3 emissions are presented for informational purposes, using the AR4 GWP of 17,200, and are not included in totals.

Table 4-89: PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture (Mg)

Year	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CF_4	115	281	168	181	198	216	227
C_2F_6	160	321	216	240	249	261	271
C_3F_8	0	18	5	5	6	13	5
C_4F_8	0	0	13	13	7	7	4
HFC-23	15	23	18	22	23	25	28
SF_6	22	45	40	40	34	36	40
NF_3	3	11	26	40	30	33	30

Methodology

Emissions are based on Partner reported emissions data received through the EPA's PFC Reduction/Climate Partnership and the EPA's PFC Emissions Vintage Model (PEVM), a model which estimates industry emissions in the absence of emission control strategies (Burton and Beizaie 2001).[123] The availability and applicability of Partner data differs across the 1990 through 2009 time series. Consequently, emissions from semiconductor manufacturing were estimated using four distinct methods, one each for the periods 1990 through 1994, 1995 through 1999, 2000 through 2006, and 2007 through 2009.

1990 through 1994

From 1990 through 1994, Partnership data was unavailable and emissions were modeled using the PEVM (Burton

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[122] Complexity is a term denoting the circuit required to connect the active circuit elements (transistors) on a chip. Increasing miniaturization, for the same chip size, leads to increasing transistor density, which, in turn, requires more complex interconnections between those transistors. This increasing complexity is manifested by increasing the levels (i.e., layers) of wiring, with each wiring layer requiring fluorinated gas usage for its manufacture.

[123] A Partner refers to a participant in the U.S. EPA PFC Reduction/Climate Partnership for the Semiconductor Industry. Through a Memorandum of Understanding (MoU) with the EPA, Partners voluntarily report their PFC emissions to the EPA by way of a third party, which aggregates the emissions.

and Beizaie 2001).[124] 1990 to 1994 emissions are assumed to be uncontrolled, since reduction strategies such as chemical substitution and abatement were yet to be developed.

PEVM is based on the recognition that PFC emissions from semiconductor manufacturing vary with: (1) the number of layers that comprise different kinds of semiconductor devices, including both silicon wafer and metal interconnect layers, and (2) silicon consumption (i.e., the area of semiconductors produced) for each kind of device. The product of these two quantities, Total Manufactured Layer Area (TMLA), constitutes the activity data for semiconductor manufacturing. PEVM also incorporates an emission factor that expresses emissions per unit of layer-area. Emissions are estimated by multiplying TMLA by this emission factor.

PEVM incorporates information on the two attributes of semiconductor devices that affect the number of layers: (1) linewidth technology (the smallest manufactured feature size), [125] and (2) product type (discrete, memory or logic).[126] For each linewidth technology, a weighted average number of layers is estimated using VLSI product-specific worldwide silicon demand data in conjunction with complexity factors (i.e., the number of layers per Integrated Circuit (IC)) specific to product type (Burton and Beizaie 2001, ITRS 2007). PEVM derives historical consumption of silicon (i.e., square inches) by linewidth technology from published data on annual wafer starts and average wafer size (VLSI Research, Inc. 2010).

The emission factor in PEVM is the average of four historical emission factors, each derived by dividing the total annual emissions reported by the Partners for each of the four years between 1996 and 1999 by the total TMLA estimated for the Partners in each of those years. Over this period, the emission factors varied relatively little (i.e., the relative standard deviation for the average was 5 percent). Since Partners are believed not to have applied significant emission reduction measures before 2000, the resulting average emission factor reflects uncontrolled emissions. The emission factor is used to estimate world uncontrolled emissions using publicly available data on world silicon consumption.

1995 through 1999

For 1995 through 1999, total U.S. emissions were extrapolated from the total annual emissions reported by the Partners (1995 through 1999). Partner-reported emissions are considered more representative (e.g., in terms of capacity utilization in a given year) than PEVM estimated emissions, and are used to generate total U.S. emissions when applicable. The emissions reported by the Partners were divided by the ratio of the total capacity of the plants operated by the Partners and the total capacity of all of the semiconductor plants in the United States; this ratio represents the share of capacity attributable to the Partnership. This method assumes that Partners and non-Partners have identical capacity utilizations and distributions of manufacturing technologies. Plant capacity data is contained in the World Fab Forecast (WFF) database and its predecessors, which is updated quarterly (Semiconductor Equipment and Materials Industry 2010).

2000 through 2006

The emission estimate for the years 2000 through 2006—the period during which Partners began the consequential application of PFC-reduction measures—was estimated using a combination of Partner reported emissions and PEVM modeled emissions. The emissions reported by Partners for each year were accepted as the quantity emitted from the share of the industry represented by those Partners. Remaining emissions, those from non-Partners, were

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[124] Various versions of the PEVM exist to reflect changing industrial practices. From 1990 to 1994 emissions estimates are from PEVM v1.0, completed in September 1998. The emission factor used to estimate 1990 to 1994 emissions is an average of the 1995 and 1996 emissions factors, which were derived from Partner reported data for those years.

[125] By decreasing features of Integrated Circuit components, more components can be manufactured per device, which increases its functionality. However, as those individual components shrink it requires more layers to interconnect them to achieve the functionality. For example, a microprocessor manufactured with the smallest feature sizes (65 nm) might contain as many as 1 billion transistors and require as many as 11 layers of component interconnects to achieve functionality while a device manufactured with 130 nm feature size might contain a few hundred million transistors and require 8 layers of component interconnects (ITRS 2007).

[126] Memory devices manufactured with the same feature sizes as microprocessors (a logic device) require approximately one-half the number of interconnect layers, whereas discrete devices require only a silicon base layer and no interconnect layers (ITRS 2007). Since discrete devices did not start using PFCs appreciably until 2004, they are only accounted for in the PEVM emissions estimates from 2004 onwards.

estimated using PEVM and the method described above. This is because non-Partners are assumed not to have implemented any PFC-reduction measures, and PEVM models emissions without such measures. The portion of the U.S. total attributed to non-Partners is obtained by multiplying PEVM's total U.S. emissions figure by the non-Partner share of U. S. total silicon capacity for each year as described above.[127,128] Annual updates to PEVM reflect published figures for actual silicon consumption from VLSI Research, Inc., revisions and additions to the world population of semiconductor manufacturing plants, and changes in IC fabrication practices within the semiconductor industry (see ITRS 2007 and Semiconductor Equipment and Materials Industry 2010).[129,130,131]

2007 through 2009

For the years 2007 through 2009, emissions were also estimated using a combination of Partner reported emissions and PEVM modeled emissions; however, two improvements were made to the estimation method employed for the previous years in the time series. First, the 2007 through 2009 emission estimates account for the fact that Partners and non-Partners employ different distributions of manufacturing technologies, with the Partners using manufacturing technologies with greater transistor densities and therefore greater numbers of layers.[132] Second, the scope of the 2007 through 2009 estimates is expanded relative to the estimates for the years 2000 through 2006 to include emissions from Research and Development (R&D) fabs. This was feasible through the use of more detailed data published in the World Fab Forecast. PEVM databases are updated annually as described above. The published world average capacity utilization for 2007 and 2008 was used for production fabs while in 2008 for R&D fabs a 20 percent figure was assumed (SIA 2009).

In addition, publicly available actual utilization data was used to account for differences in fab utilization for manufacturers of discrete and IC products for the emissions in 2009 for non-partners. PEVM estimates were adjusted using technology weighted capacity shares that reflect relative influence of different utilization.

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[127] This approach assumes that the distribution of linewidth technologies is the same between Partners and non-Partners. As discussed in the description of the method used to estimate 2007 emissions, this is not always the case.

[128] Generally 5 percent or less of the fields needed to estimate TMLA shares are missing values in the World Fab Watch databases. In the 2007 World Fab Watch database used to generate the 2006 non-Partner TMLA capacity share, these missing values were replaced with the corresponding mean TMLA across fabs manufacturing similar classes of products. However, the impact of replacing missing values on the non-Partner TMLA capacity share was inconsequential.

[129] Special attention was given to the manufacturing capacity of plants that use wafers with 300 mm diameters because the actual capacity of these plants is ramped up to design capacity, typically over a 2–3 year period. To prevent overstating estimates of partner-capacity shares from plants using 300 mm wafers, *design* capacities contained in WFW were replaced with estimates of *actual installed* capacities for 2004 published by Citigroup Smith Barney (2005). Without this correction, the partner share of capacity would be overstated, by approximately 5 percent. For perspective, approximately 95 percent of all new capacity additions in 2004 used 300 mm wafers, and by year-end those plants, on average, could operate at approximately 70 percent of the design capacity. For 2005, actual installed capacities were estimated using an entry in the World Fab Watch database (April 2006 Edition) called "wafers/month, 8-inch equivalent," which denoted the actual installed capacity instead of the fully-ramped capacity. For 2006, actual installed capacities of new fabs were estimated using an average monthly ramp rate of 1100 wafer starts per month (wspm) derived from various sources such as semiconductor fabtech, industry analysts, and articles in the trade press. The monthly ramp rate was applied from the first-quarter of silicon volume (FQSV) to determine the average design capacity over the 2006 period.

[130] In 2006, the industry trend in co-ownership of manufacturing facilities continued. Several manufacturers, who are Partners, now operate fabs with other manufacturers, who in some cases are also Partners and in other cases are not Partners. Special attention was given to this occurrence when estimating the Partner and non-Partner shares of U.S. manufacturing capacity.

[131] Two versions of PEVM are used to model non-Partner emissions during this period. For the years 2000 to 2003 PEVM v3.2.0506.0507 was used to estimate non-Partner emissions. During this time, discrete devices did not use PFCs during manufacturing and therefore only memory and logic devices were modeled in the PEVM v3.2.0506.0507. From 2004 onwards, discrete device fabrication started to use PFCs, hence PEVM v4.0.0701.0701, the first version of PEVM to account for PFC emissions from discrete devices, was used to estimate non-Partner emissions for this time period.

[132] EPA considered applying this change to years before 2007, but found that it would be difficult due to the large amount of data (i.e., technology-specific global and non-Partner TMLA) that would have to be examined and manipulated for each year. This effort did not appear to be justified given the relatively small impact of the improvement on the total estimate for 2007 and the fact that the impact of the improvement would likely be lower for earlier years because the estimated share of emissions accounted for by non-Partners is growing as Partners continue to implement emission-reduction efforts.

Gas-Specific Emissions

Two different approaches were also used to estimate the distribution of emissions of specific fluorinated gases. Before 1999, when there was no consequential adoption of fluorinated-gas-reducing measures, a fixed distribution of fluorinated-gas use was assumed to apply to the entire U.S. industry. This distribution was based upon the average fluorinated-gas purchases made by semiconductor manufacturers during this period and the application of IPCC default emission factors for each gas (Burton and Beizaie 2001). For the 2000 through 2009 period, the 1990 through 1999 distribution was assumed to apply to the non-Partners. Partners, however, began reporting gas-specific emissions during this period. Thus, gas-specific emissions for 2000 through 2009 were estimated by adding the emissions reported by the Partners to those estimated for the non-Partners.

Data Sources

Partners estimate their emissions using a range of methods. For 2009, it is assumed that most Partners used a method at least as accurate as the IPCC's Tier 2a Methodology, recommended in the 2006 IPCC Guidelines for National Greenhouse Inventories (IPCC 2006). Data used to develop emission estimates are attributed in part to estimates provided by the members of the Partnership, and in part from data obtained from PEVM estimates. Estimates of operating plant capacities and characteristics for Partners and non-Partners were derived from the Semiconductor Equipment and Materials Industry (SEMI) World Fab Forecast (formerly World Fab Watch) database (1996 through 2009) (e.g., Semiconductor Materials and Equipment Industry, 2010). Actual world capacity utilizations for 2009 were obtained from Semiconductor International Capacity Statistics (SICAS) (SIA, 2009). Estimates of silicon consumed by linewidth from 1990 through 2009 were derived from information from VLSI Research, Inc. (2010), and the number of layers per linewidth was obtained from International Technology Roadmap for Semiconductors: 2006 Update (Burton and Beizaie 2001, ITRS 2007, ITRS 2008).

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis of this source category was performed using the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The equation used to estimate uncertainty is:

$$\text{U.S. emissions} = \sum \text{Partnership gas-specific submittals} + [(\text{non-Partner share of World TMLA}) \times (\text{PEVM Emission Factor} \times \text{World TMLA})]$$

The Monte Carlo analysis results presented below relied on estimates of uncertainty attributed to the four quantities on the right side of the equation. Estimates of uncertainty for the four quantities were in turn developed using the estimated uncertainties associated with the individual inputs to each quantity, error propagation analysis, Monte Carlo simulation, and expert judgment. The relative uncertainty associated with World TMLA estimate in 2009 is about ±10 percent, based on the uncertainty estimate obtained from discussions with VLSI, Inc. For the share of World layer-weighted silicon capacity accounted for by non-Partners, a relative uncertainty of ±8 percent was estimated based on a separate Monte Carlo simulation to account for the random occurrence of missing data in the World Fab Watch database. For the aggregate PFC emissions data supplied to the partnership, a relative uncertainty of ±50 percent was estimated for each gas-specific PFC emissions value reported by an individual Partner, and error propagation techniques were used to estimate uncertainty for total Partnership gas-specific submittals.[133] A relative uncertainty of approximately ±10 percent was estimated for the PEVM emission factor, based on the standard deviation of the 1996 to 1999 emission factors.[134] All estimates of uncertainties are given at 95-percent confidence intervals.

In developing estimates of uncertainty, consideration was also given to the nature and magnitude of the potential bias that World activity data (i.e., World TMLA) might have in its estimates of the number of layers associated with devices manufactured at each technology node. The result of a brief analysis indicated that U.S. TMLA overstates the average number of layers across all product categories and all manufacturing technologies for 2004 by 0.12 layers or 2.9 percent. The same upward bias is assumed for World TMLA, and is represented in the uncertainty analysis by deducting the absolute bias value from the World activity estimate when it is incorporated into the

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[133] Error propagation resulted in Partnership gas-specific uncertainties ranging from 17 to 27 percent·

[134] The average of 1996 to 1999 emission factor is used to derive the PEVM emission factor.

Monte Carlo analysis.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-90. The emissions estimate for total U.S. PFC emissions from semiconductor manufacturing were estimated to be between 4.8 and 5.9 Tg CO_2 Eq. at a 95 percent confidence level. This range represents 10 percent below to 11 percent above the 2009 emission estimate of 5.3 Tg CO_2 Eq. This range and the associated percentages apply to the estimate of total emissions rather than those of individual gases. Uncertainties associated with individual gases will be somewhat higher than the aggregate, but were not explicitly modeled.

Table 4-90: Tier 2 Quantitative Uncertainty Estimates for HFC, PFC, and SF_6 Emissions from Semiconductor Manufacture (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate[a] (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[b] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound[c]	**Upper Bound[c]**	**Lower Bound**	**Upper Bound**
Semiconductor Manufacture	HFC, PFC, and SF_6	5.3	4.8	5.9	−10%	+11%

[a] Because the uncertainty analysis covered all emissions (including NF_3), the emission estimate presented here does not match that shown in Table 4-88.

[b] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

[c] Absolute lower and upper bounds were calculated using the corresponding lower and upper bounds in percentages.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

With the exception of possible future updates to emission factors, the method to estimate non-Partner related emissions (i.e., PEVM) is not expected to change. Future improvements to the national emission estimates will primarily be associated with determining the portion of national emissions to attribute to Partner report totals (about 80 percent in recent years) and improvements in estimates of non-Partner totals. As the nature of the Partner reports change through time and industry-wide reduction efforts increase, consideration will be given to what emission reduction efforts—if any—are likely to be occurring at non-Partner facilities. Currently, none are assumed to occur.

Another point of consideration for future national emissions estimates is the inclusion of PFC emissions from heat transfer fluid (HTF) loss to the atmosphere and the production of photovoltaic cells (PVs). Heat transfer fluids, of which some are liquid perfluorinated compounds, are used during testing of semiconductor devices and, increasingly, are used to manage heat during the manufacture of semiconductor devices. Evaporation of these fluids is a source of emissions (EPA 2006). PFCs are also used during manufacture of PV cells that use silicon technology, specifically, crystalline, polycrystalline, and amorphous silicon technologies. PV manufacture is growing in the United States, and therefore may be expected to constitute a growing share of U.S. PFC emissions from the electronics sector.

4.22. Electrical Transmission and Distribution (IPCC Source Category 2F7)

The largest use of SF_6, both in the United States and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity (RAND 2004). The gas has been employed by the electric power industry in the United States since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, and other switchgear. Sulfur hexafluoride has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas.

Fugitive emissions of SF_6 can escape from gas-insulated substations and switchgear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal. Emissions of SF_6 from equipment manufacturing and from electrical transmission and distribution systems were estimated to be 12.8 Tg CO_2 Eq. (0.5 Gg) in 2009. This quantity represents a 55 percent decrease from the estimate for 1990 (see Table 4-91 and Table 4-92). This decrease is believed to have two causes: a sharp increase in the price of SF_6 during the 1990s and a growing awareness of the environmental impact of SF_6 emissions through programs such as EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

Table 4-91: SF_6 Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Tg CO_2 Eq.)

Year	Electric Power Systems	Electrical Equipment Manufacturers	Total
1990	28.1	0.3	28.4
2000	15.4	0.7	16.0
2005	14.1	1.1	15.1
2006	13.1	1.0	14.1
2007	12.4	0.8	13.2
2008	12.1	1.3	13.3
2009	12.1	0.7	12.8

Note: Totals may not sum due to independent rounding.

Table 4-92: SF_6 Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Gg)

Year	Emissions
1990	1.2
2000	0.7
2005	0.6
2006	0.6
2007	0.6
2008	0.6
2009	0.5

Methodology

The estimates of emissions from Electric Transmission and Distribution are comprised of emissions from electric power systems and emissions from the manufacture of electrical equipment. The methodologies for estimating both sets of emissions are described below.

1999 through 2009 Emissions from Electric Power Systems

Emissions from electric power systems from 1999 to 2009 were estimated based on: (1) reporting from utilities participating in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems (Partners), which began in 1999; and, (2) the relationship between emissions and utilities' transmission miles as reported in the 2001, 2004, 2007, and 2010 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors (UDI 2001, 2004, 2007, 2010). (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV.) Over the period from 1999 to 2009, Partner utilities, which for inventory purposes are defined as utilities that either currently are or previously have been part of the Partnership, represented between 42 percent and 47 percent of total U.S. transmission miles. For each year, the emissions reported by or estimated for Partner utilities were added to the emissions estimated for utilities that have never participated in the Partnership (i.e., non-Partners).[135]

Partner utilities estimated their emissions using a Tier 3 utility-level mass balance approach (IPCC 2006). If a Partner utility did not provide data for a particular year, emissions were interpolated between years for which data were available or extrapolated based on Partner-specific transmission mile growth rates. In 2009, non-reporting Partners accounted for approximately 8 percent of the total emissions attributed to Partner utilities.

Emissions from non-Partners in every year since 1999 were estimated using the results of a regression analysis that showed that the emissions from reporting utilities were most strongly correlated with their transmission miles. The results of this analysis are not surprising given that, in the United States, SF_6 is contained primarily in transmission

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[135] Partners in EPA's SF_6 Emission Reduction Partnership reduced their emissions by approximately 61% from 1999 to 2008.

equipment rated above 34.5 kV. The equations were developed based on the 1999 SF_6 emissions reported by a subset of 42 Partner utilities (representing approximately 23 percent of U.S. transmission miles) and 2000 transmission mileage data obtained from the 2001 UDI Directory of Electric Power Producers and Distributors (UDI 2001). Two equations were developed, one for small and one for large utilities (i.e., with fewer or more than 10,000 transmission miles, respectively). The distinction between utility sizes was made because the regression analysis showed that the relationship between emissions and transmission miles differed for small and large transmission networks. The same equations were used to estimate non-Partner emissions in 1999 and every year thereafter because non-Partners were assumed not to have implemented any changes that would have resulted in reduced emissions since 1999.

The regression equations are:

Non-Partner small utilities (fewer than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 1.001 \times \text{Transmission Miles}$$

Non-Partner large utilities (more than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 0.58 \times \text{Transmission Miles}$$

Data on transmission miles for each non-Partner utility for the years 2000, 2003, 2006, and 2009 were obtained from the 2001, 2004, 2007, and 2010 UDI Directories of Electric Power Producers and Distributors, respectively (UDI 2001, 2004, 2007, 2010). The U.S. transmission system grew by over 25,000 miles between 2000 and 2003 and by over 52,000 miles between 2003 and 2006. These periodic increases are assumed to have occurred gradually. Therefore, transmission mileage was assumed to increase at an annual rate of 1.3 percent between 2000 and 2003 and 2.6 percent between 2003 and 2006. This growth rate slowed to 0.2% from 2006 to 2009 as transmission miles increased by just 4,400 miles (approximately).

As a final step, total electric power system emissions were determined for each year by summing the Partner reported and estimated emissions (reported data was available through the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems) and the non-Partner emissions (determined using the 1999 regression equations).

1990 through 1998 Emissions from Electric Power Systems

Because most participating utilities reported emissions only for 1999 through 2009, modeling was used to estimate SF_6 emissions from electric power systems for the years 1990 through 1998. To perform this modeling, U.S. emissions were assumed to follow the same trajectory as global emissions from this source during the 1990 to 1999 period. To estimate global emissions, the RAND survey of global SF_6 sales were used, together with the following equation for estimating emissions, which is derived from the mass-balance equation for chemical emissions (Volume 3, Equation 7.3) in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).[136] (Although equation 7.3 of the IPCC Guidelines appears in the discussion of substitutes for ozone-depleting substances, it is applicable to emissions from any long-lived pressurized equipment that is periodically serviced during its lifetime.)

$$\text{Emissions (kilograms } SF_6) = SF_6 \text{ purchased to refill existing equipment (kilograms)} + \text{nameplate capacity of retiring equipment (kilograms)}$$ [137]

Note that the above equation holds whether the gas from retiring equipment is released or recaptured; if the gas is recaptured, it is used to refill existing equipment, thereby lowering the amount of SF_6 purchased by utilities for this purpose.

Gas purchases by utilities and equipment manufacturers from 1961 through 2003 are available from the RAND (2004) survey. To estimate the quantity of SF_6 released or recovered from retiring equipment, the nameplate capacity of retiring equipment in a given year was assumed to equal 81.2 percent of the amount of gas purchased by

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[136] Ideally, sales to utilities in the U.S. between 1990 and 1999 would be used as a model. However, this information was not available. There were only two U.S. manufacturers of SF_6 during this time period, so it would not have been possible to conceal sensitive sales information by aggregation.

[137] Nameplate capacity is defined as the amount of SF_6 within fully charged electrical equipment.

electrical equipment manufacturers 40 years previous (e.g., in 2000, the nameplate capacity of retiring equipment was assumed to equal 81.2 percent of the gas purchased in 1960). The remaining 18.8 percent was assumed to have been emitted at the time of manufacture. The 18.8 percent emission factor is an average of IPCC default SF_6 emission rates for Europe and Japan for 1995 (IPCC 2006). The 40-year lifetime for electrical equipment is also based on IPCC (2006). The results of the two components of the above equation were then summed to yield estimates of global SF_6 emissions from 1990 through 1999.

U.S. emissions between 1990 and 1999 are assumed to follow the same trajectory as global emissions during this period. To estimate U.S. emissions, global emissions for each year from 1990 through 1998 were divided by the estimated global emissions from 1999. The result was a time series of factors that express each year's global emissions as a multiple of 1999 global emissions. Historical U.S. emissions were estimated by multiplying the factor for each respective year by the estimated U.S. emissions of SF_6 from electric power systems in 1999 (estimated to be 15.0 Tg CO_2 Eq.).

Two factors may affect the relationship between the RAND sales trends and actual global emission trends. One is utilities' inventories of SF_6 in storage containers. When SF_6 prices rise, utilities are likely to deplete internal inventories before purchasing new SF_6 at the higher price, in which case SF_6 sales will fall more quickly than emissions. On the other hand, when SF_6 prices fall, utilities are likely to purchase more SF_6 to rebuild inventories, in which case sales will rise more quickly than emissions. This effect was accounted for by applying 3-year smoothing to utility SF_6 sales data. The other factor that may affect the relationship between the RAND sales trends and actual global emissions is the level of imports from and exports to Russia and China. SF_6 production in these countries is not included in the RAND survey and is not accounted for in any another manner by RAND. However, atmospheric studies confirm that the downward trend in estimated global emissions between 1995 and 1998 was real (see the Uncertainty discussion below).

1990 through 2009 Emissions from Manufacture of Electrical Equipment

The 1990 to 2009 emission estimates for original equipment manufacturers (OEMs) were derived by assuming that manufacturing emissions equal 10 percent of the quantity of SF_6 provided with new equipment. The quantity of SF_6 provided with new equipment was estimated based on statistics compiled by the National Electrical Manufacturers Association (NEMA). These statistics were provided for 1990 to 2000; the quantities of SF_6 provided with new equipment for 2001 to 2009 were estimated using Partner reported data and the total industry SF_6 nameplate capacity estimate (137.4 Tg CO_2 Eq. in 2009). Specifically, the ratio of new nameplate capacity to total nameplate capacity of a subset of Partners for which new nameplate capacity data was available from 1999 to 2009 was calculated. This ratio was then multiplied by the total industry nameplate capacity estimate to derive the amount of SF_6 provided with new equipment for the entire industry. The 10 percent emission rate is the average of the "ideal" and "realistic" manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell et al. 2002).

Uncertainty

To estimate the uncertainty associated with emissions of SF_6 from Electric Transmission and Distribution, uncertainties associated with three quantities were estimated: (1) emissions from Partners, (2) emissions from non-Partners, and (3) emissions from manufacturers of electrical equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

Total emissions from the SF_6 Emission Reduction Partnership include emissions from both reporting and non-reporting Partners. For reporting Partners, individual Partner-reported SF_6 data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of all Partner reported data was estimated to be 5.3 percent. The uncertainty associated with extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2009 from non-Partners: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and (2) the uncertainty in total transmission miles for non-Partners. In addition, there is uncertainty associated with the assumption that the emission factor used for non-Partner utilities (which accounted for approximately 57 percent of U.S. transmission miles in 2009) will remain at levels defined by Partners who reported in 1999. However, the last source of uncertainty was not modeled.

Uncertainties were also estimated regarding (1) the quantity of SF_6 supplied with equipment by equipment manufacturers, which is projected from Partner provided nameplate capacity data and industry SF_6 nameplate capacity estimates, and (2) the manufacturers' SF_6 emissions rate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-93. Electrical Transmission and Distribution SF_6 emissions were estimated to be between 10.2 and 15.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 22 percent above the emission estimate of 12.8 Tg CO_2 Eq.

Table 4-93: Tier 2 Quantitative Uncertainty Estimates for SF_6 Emissions from Electrical Transmission and Distribution (Tg CO_2 Eq. and percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to 2009 Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Electrical Transmission and Distribution	SF_6	12.8	10.2	15.7	-21%	+22%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

In addition to the uncertainty quantified above, there is uncertainty associated with using global SF_6 sales data to estimate U.S. emission trends from 1990 through 1999. However, the trend in global emissions implied by sales of SF_6 appears to reflect the trend in global emissions implied by changing SF_6 concentrations in the atmosphere. That is, emissions based on global sales declined by 29 percent between 1995 and 1998, and emissions based on atmospheric measurements declined by 27 percent over the same period.

Several pieces of evidence indicate that U.S. SF_6 emissions were reduced as global emissions were reduced. First, the decreases in sales and emissions coincided with a sharp increase in the price of SF_6 that occurred in the mid-1990s and that affected the United States as well as the rest of the world. A representative from DILO, a major manufacturer of SF_6 recycling equipment, stated that most U.S. utilities began recycling rather than venting SF_6 within two years of the price rise. Finally, the emissions reported by the one U.S. utility that reported 1990 through 1999 emissions to EPA showed a downward trend beginning in the mid-1990s.

Recalculations Discussion

SF_6 emission estimates for the period 1990 through 2008 were updated based on (1) new data from EPA's SF_6 Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. Updating the 2004 transmission mile data for the Partner changed the annual transmission mile growth rates used to extrapolate total U.S. transmission mile values for years in which a UDI database was not purchased (including 1999). This recalculation impacted emission estimates in two ways. First, the regression coefficients used to estimate emissions for non-Partners are based on 1999 transmission miles and emissions for Partners that reported emissions in 1999, so the change in 1999 transmission miles affected the regression coefficients. The result was that the regression coefficient for utilities with fewer than 10,000 transmission miles increased from 0.89 to 1.001 kg of emissions per transmission mile, while the regression coefficient for utilities with more than 10,000 transmission miles increased very slightly from 0.577 to 0.578 kg of emissions per transmission mile. The second impact of the updated annual transmission mile growth rates was that the total non-Partner transmission miles that the regression coefficients are applied to were also affected. Based on the revisions listed above, SF_6 emissions from electric transmission and distribution increased between 4 to 9 percent for each year from 1990 through 2008.

In addition, the method for estimating potential emissions from the sector was updated for the 1990-2009 Inventory. In previous years, potential emissions were assumed to equal total industry SF_6 purchases, which were developed from two components: (1) purchases by Partner utilities from bulk gas distributors, and (2) purchases by electrical equipment manufacturers from bulk gas distributors. This previous method led to concerns of double-counting since Partners sometimes were recording all SF_6 received in cylinders from any source (including equipment manufacturers) as gas received from bulk distributors. Therefore, SF_6 that was purchased by a utility from an equipment manufacturer was sometimes counted as a purchase by both the equipment manufacturer and the utility. The new method still assumes that potential emissions are equal to industry purchases, but estimates total purchases for the industry by adding the total amount of gas purchased by all U.S. utilities from any source (bulk distributor or equipment manufacturer) to estimated emissions from equipment manufacturers. It is assumed that all SF_6 purchased by equipment manufacturers is either emitted or sent to utilities.

4.23. Industrial Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, many industrial processes generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from non-energy industrial processes from 1990 to 2009 are reported in Table 4-94.

Table 4-94: NO_x, CO, and NMVOC Emissions from Industrial Processes (Gg)

Gas/Source	**1990**	**1995**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
NO_x	**591**	**607**	**626**	**569**	**553**	**537**	**520**	**568**
Other Industrial Processes	343	362	435	437	418	398	379	436
Chemical & Allied Product Manufacturing	152	143	95	55	57	59	61	55
Metals Processing	88	89	81	60	61	62	62	60
Storage and Transport	3	5	14	15	15	16	16	15
Miscellaneous*	5	8	2	2	2	2	2	2
CO	**4,125**	**3,959**	**2,216**	**1,555**	**1,597**	**1,640**	**1,682**	**1,549**
Metals Processing	2,395	2,159	1,175	752	788	824	859	752
Other Industrial Processes	487	566	537	484	474	464	454	484
Chemical & Allied Product Manufacturing	1,073	1,110	327	189	206	223	240	187
Storage and Transport	69	23	153	97	100	103	104	97
Miscellaneous*	101	102	23	32	30	27	25	29
NMVOCs	**2,422**	**2,642**	**1,773**	**1,997**	**1,933**	**1,869**	**1,804**	**1,322**
Storage and Transport	1,352	1,499	1,067	1,308	1,266	1,224	1,182	662
Other Industrial Processes	364	408	412	415	398	383	367	395
Chemical & Allied Product Manufacturing	575	599	230	213	211	210	207	206
Metals Processing	111	113	61	44	44	43	42	44
Miscellaneous*	20	23	3	17	14	10	7	15

* Miscellaneous includes the following categories: catastrophic/accidental release, other combustion, health services, cooling towers, and fugitive dust. It does not include agricultural fires or slash/prescribed burning, which are accounted for under the Field Burning of Agricultural Residues source.

Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

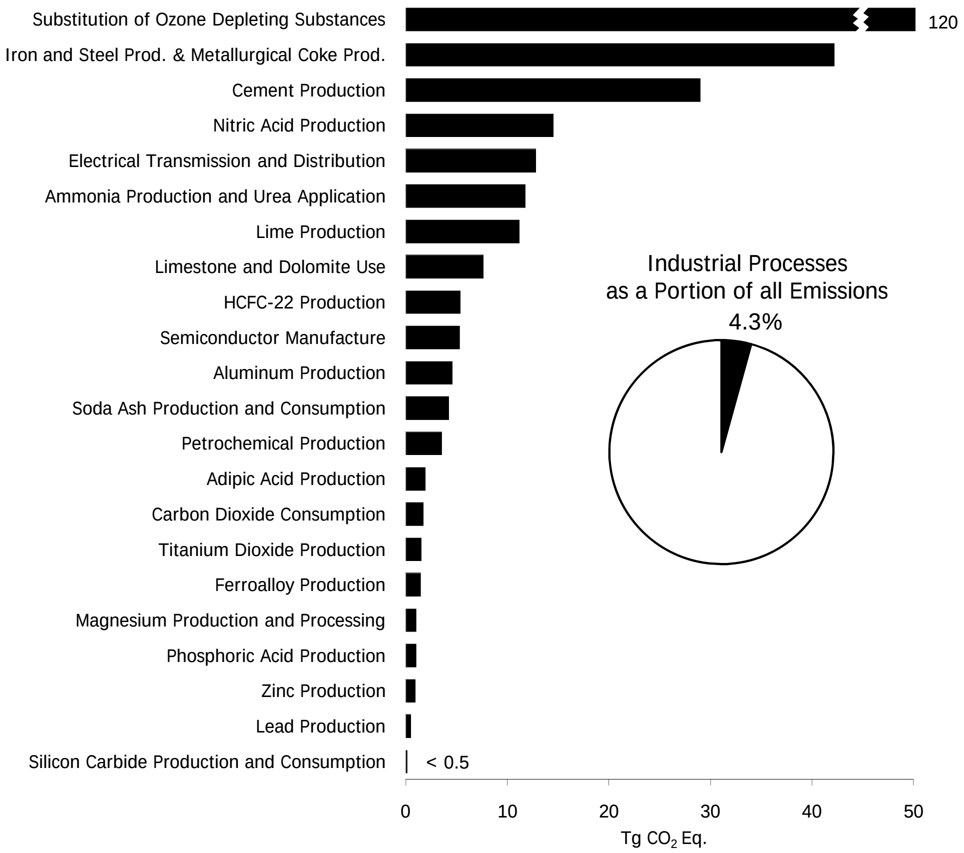

Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

5. Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, emissions from Nitrous Oxide (N_2O) Product Uses, the only source of greenhouse gas emissions from this sector, accounted for less than 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a CO_2 equivalent basis in 2009 (see Table 5-1). Indirect greenhouse gas emissions also result from solvent and other product use, and are presented in Table 5-5 in gigagrams (Gg).

Table 5-1: N_2O Emissions from Solvent and Other Product Use (Tg CO_2 Eq. and Gg)

Gas/Source	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
N_2O from Product Uses									
Tg CO_2 Eq.	4.4		4.9		4.4	4.4	4.4	4.4	4.4
Gg	14		16		14	14	14	14	14

5.1. *Nitrous Oxide from Product Uses (IPCC Source Category 3D)*

N_2O is a clear, colorless, oxidizing liquefied gas, with a slightly sweet odor. Two companies operate a total of five N_2O production facilities in the United States (Airgas 2007; FTC 2001). N_2O is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general anesthesia, and as an anesthetic in various dental and veterinary applications. As such, it is used to treat short-term pain, for sedation in minor elective surgeries, and as an induction anesthetic. The second main use of N_2O is as a propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream. Small quantities of N_2O also are used in the following applications:

- Oxidizing agent and etchant used in semiconductor manufacturing;
- Oxidizing agent used, with acetylene, in atomic absorption spectrometry;
- Production of sodium azide, which is used to inflate airbags;
- Fuel oxidant in auto racing; and
- Oxidizing agent in blowtorches used by jewelers and others (Heydorn 1997).

Production of N_2O in 2009 was approximately 15 Gg (Table 5-2).

Table 5-2: N_2O Production (Gg)

Year	**Gg**
1990	16
2000	17
2005	15
2006	15
2007	15
2008	15
2009	15

N_2O emissions were 4.4 Tg CO_2 Eq. (14 Gg) in 2009 (Table 5-3). Production of N_2O stabilized during the 1990s because medical markets had found other substitutes for anesthetics, and more medical procedures were being performed on an outpatient basis using local anesthetics that do not require N_2O. The use of N_2O as a propellant for whipped cream has also stabilized due to the increased popularity of cream products packaged in reusable plastic tubs (Heydorn 1997).

Table 5-3: N_2O Emissions from N_2O Product Usage (Tg CO_2 Eq. and Gg)

Year	**Tg CO_2 Eq.**	**Gg**
1990	4.4	14

2000	4.9	16
2005	4.4	14
2006	4.4	14
2007	4.4	14
2008	4.4	14
2009	4.4	14

Methodology

Emissions from N_2O product usage were calculated by first multiplying the total amount of N_2O produced in the United States by the share of the total quantity of N_2O attributed to each end use. This value was then multiplied by the associated emission rate for each end use. After the emissions were calculated for each end use, they were added together to obtain a total estimate of N_2O product usage emissions. Emissions were determined using the following equation:

$$N_2O \text{ Product Usage Emissions} = \sum i \text{ [Total U.S. Production of } N_2O] \times \text{[Share of Total Quantity of } N_2O \text{ Usage by Sector i]} \times \text{[Emissions Rate for Sector i]}$$

where,

i = Sector.

The share of total quantity of N_2O usage by end use represents the share of national N_2O produced that is used by the specific subcategory (i.e., anesthesia, food processing, etc.). In 2009, the medical/dental industry used an estimated 89.5 percent of total N_2O produced, followed by food processing propellants at 6.5 percent. All other categories combined used the remainder of the N_2O produced. This subcategory breakdown has changed only slightly over the past decade. For instance, the small share of N_2O usage in the production of sodium azide has declined significantly during the 1990s. Due to the lack of information on the specific time period of the phase-out in this market subcategory, most of the N_2O usage for sodium azide production is assumed to have ceased after 1996, with the majority of its small share of the market assigned to the larger medical/dental consumption subcategory (Heydorn 1997). The N_2O was allocated across the following categories: medical applications, food processing propellant, and sodium azide production (pre-1996). A usage emissions rate was then applied for each sector to estimate the amount of N_2O emitted.

Only the medical/dental and food propellant subcategories were estimated to release emissions into the atmosphere, and therefore these subcategories were the only usage subcategories with emission rates. For the medical/dental subcategory, due to the poor solubility of N_2O in blood and other tissues, none of the N_2O is assumed to be metabolized during anesthesia and quickly leaves the body in exhaled breath. Therefore, an emission factor of 100 percent was used for this subcategory (IPCC 2006). For N_2O used as a propellant in pressurized and aerosol food products, none of the N_2O is reacted during the process and all of the N_2O is emitted to the atmosphere, resulting in an emission factor of 100 percent for this subcategory (IPCC 2006). For the remaining subcategories, all of the N_2O is consumed/reacted during the process, and therefore the emission rate was considered to be zero percent (Tupman 2002).

The 1990 through 1992 N_2O production data were obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997). N_2O production data for 1993 through 1995 were not available. Production data for 1996 was specified as a range in two data sources (Heydorn 1997, Tupman 2002). In particular, for 1996, Heydorn (1997) estimates N_2O production to range between 13.6 and 18.1 thousand metric tons. Tupman (2003) provided a narrower range (15.9 to 18.1 thousand metric tons) for 1996 that falls within the production bounds described by Heydorn (1997). Tupman (2003) data are considered more industry-specific and current. Therefore, the midpoint of the narrower production range was used to estimate N_2O emissions for years 1993 through 2001 (Tupman 2003). The 2002 and 2003 N_2O production data were obtained from the Compressed Gas Association Nitrous Oxide Fact Sheet and Nitrous Oxide Abuse Hotline (CGA 2002, 2003). These data were also provided as a range. For example, in 2003, CGA (2003) estimates N_2O production to range between 13.6 and 15.9 thousand metric tons. Due to unavailable data, production estimates for years 2004 through 2009 were held at the 2003 value.

The 1996 share of the total quantity of N_2O used by each subcategory was obtained from SRI Consulting's Nitrous

Oxide, North America report (Heydorn 1997). The 1990 through 1995 share of total quantity of N_2O used by each subcategory was kept the same as the 1996 number provided by SRI Consulting. The 1997 through 2001share of total quantity of N_2O usage by sector was obtained from communication with a N_2O industry expert (Tupman 2002). The 2002 and 2003 share of total quantity of N_2O usage by sector was obtained from CGA (2002, 2003). Due to unavailable data, the share of total quantity of N_2O usage data for years 2004 through 2009 was assumed to equal the 2003 value. The emissions rate for the food processing propellant industry was obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997), and confirmed by a N_2O industry expert (Tupman 2002). The emissions rate for all other subcategories was obtained from communication with a N_2O industry expert (Tupman 2002). The emissions rate for the medical/dental subcategory was obtained from the 2006 IPCC Guidelines.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N_2O emission estimate from N_2O product usage was calculated using the IPCC Guidelines for National Greenhouse Gas Inventories (2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N_2O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 5-4. N_2O emissions from N_2O product usage were estimated to be between 4.1 and 4.7 Tg CO_2 Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 8 percent below to 8 percent above the 2009 emissions estimate of 4.4 Tg CO_2 Eq.

Table 5-4: Tier 2 Quantitative Uncertainty Estimates for N_2O Emissions from N_2O Product Usage (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
N_2O Product Usage	N_2O	4.4	4.1	4.7	-8%	+8%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note that this uncertainty range (±8 percent) has increased by 12 percent compared to the uncertainty range in last year's Inventory (±2 percent), due to a correction to the uncertainty input parameters. Furthermore, methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time-series are described in more detail in the Methodology section, above.

Planned Improvements

Planned improvements include a continued evaluation of alternative production statistics for cross verification, a reassessment of N_2O product use subcategories to accurately represent trends, investigation of production and use cycles, and the potential need to incorporate a time lag between production and ultimate product use and resulting release of N_2O. Additionally, planned improvements include considering imports and exports of N_2O for product uses.

5.2. Indirect Greenhouse Gas Emissions from Solvent Use

The use of solvents and other chemical products can result in emissions of various ozone precursors (i.e., indirect greenhouse gases).[138] Non-CH_4 volatile organic compounds (NMVOCs), commonly referred to as "hydrocarbons," are the primary gases emitted from most processes employing organic or petroleum based solvents. As some of industrial applications also employ thermal incineration as a control technology, combustion by-products, such as carbon monoxide (CO) and nitrogen oxides (NO_x), are also reported with this source category. In the United States,

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[138] Solvent usage in the United States also results in the emission of small amounts of hydrofluorocarbons (HFCs) and hydrofluoroethers (HFEs), which are included under Substitution of Ozone Depleting Substances in the Industrial Processes chapter.

emissions from solvents are primarily the result of solvent evaporation, whereby the lighter hydrocarbon molecules in the solvents escape into the atmosphere. The evaporation process varies depending on different solvent uses and solvent types. The major categories of solvent uses include: degreasing, graphic arts, surface coating, other industrial uses of solvents (i.e., electronics, etc.), dry cleaning, and non-industrial uses (i.e., uses of paint thinner, etc.).

Total emissions of NO_x, NMVOCs, and CO from 1990 to 2009 are reported in Table 5-5.

Table 5-5: Emissions of NO_x, CO, and NMVOC from Solvent Use (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	**1**	**3**	**3**	**4**	**4**	**4**	**3**
Surface Coating	1	3	3	4	4	4	3
Graphic Arts	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Other Industrial Processes[a]	+	+	+	+	+	+	+
Non-Industrial Processes[b]	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
CO	**5**	**45**	**2**	**2**	**2**	**2**	**2**
Surface Coating	+	45	2	2	2	2	2
Other Industrial Processes[a]	4	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Graphic Arts	+	+	+	+	+	+	+
Non-Industrial Processes[b]	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
NMVOCs	**5,216**	**4,384**	**3,851**	**3,846**	**3,839**	**3,834**	**2,583**
Surface Coating	2,289	1,766	1,578	1,575	1,573	1,571	1,058
Non-Industrial Processes[b]	1,724	1,676	1,446	1,444	1,441	1,439	970
Degreasing	675	316	280	280	280	279	188
Dry Cleaning	195	265	230	230	229	229	154
Graphic Arts	249	222	194	193	193	193	130
Other Industrial Processes[a]	85	98	88	88	87	87	59
Other	+	40	36	36	36	36	24

[a] Includes rubber and plastics manufacturing, and other miscellaneous applications.

[b] Includes cutback asphalt, pesticide application adhesives, consumer solvents, and other miscellaneous applications.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

Emissions were calculated by aggregating solvent use data based on information relating to solvent uses from different applications such as degreasing, graphic arts, etc. Emission factors for each consumption category were then applied to the data to estimate emissions. For example, emissions from surface coatings were mostly due to solvent evaporation as the coatings solidify. By applying the appropriate solvent-specific emission factors to the amount of solvents used for surface coatings, an estimate of emissions was obtained. Emissions of CO and NO_x result primarily from thermal and catalytic incineration of solvent-laden gas streams from painting booths, printing operations, and oven exhaust.

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of solvent purchased) as an indicator of emissions. National activity data were collected for individual applications from various agencies.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and the reliability of correlations between activity data and actual emissions.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

6. Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes. This chapter provides an assessment of non-carbon-dioxide emissions from the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues (see Figure 6-1). Carbon dioxide (CO_2) emissions and removals from agriculture-related land-use activities, such as liming of agricultural soils and conversion of grassland to cultivated land, are presented in the Land Use, Land-Use Change, and Forestry chapter. Carbon dioxide emissions from on-farm energy use are accounted for in the Energy chapter.

Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Emission Sources

In 2009, the Agriculture sector was responsible for emissions of 419.3 teragrams of CO_2 equivalents (Tg CO_2 Eq.), or 6.3 percent of total U.S. greenhouse gas emissions. Methane (CH_4) and nitrous oxide (N_2O) were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represent about 20 percent and 7 percent of total CH_4 emissions from anthropogenic activities, respectively. Of all domestic animal types, beef and dairy cattle were by far the largest emitters of CH_4. Rice cultivation and field burning of agricultural residues were minor sources of CH_4. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions, accounting for 69 percent. Manure management and field burning of agricultural residues were also small sources of N_2O emissions.

Table 6-1 and Table 6-2 present emission estimates for the Agriculture sector. Between 1990 and 2009, CH_4 emissions from agricultural activities increased by 14.9 percent, while N_2O emissions fluctuated from year to year, but overall increased by 4.8 percent.

Table 6-1: Emissions from Agriculture (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**171.2**	**186.7**	**190.1**	**191.7**	**198.2**	**197.5**	**196.8**
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N_2O	**212.4**	**224.0**	**228.7**	**227.1**	**227.6**	**228.8**	**222.5**
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**383.6**	**410.6**	**418.8**	**418.8**	**425.8**	**426.3**	**419.3**

Note: Totals may not sum due to independent rounding.

Table 6-2: Emissions from Agriculture (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**8,153**	**8,890**	**9,052**	**9,129**	**9,437**	**9,405**	**9,372**
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Rice Cultivation	339	357	326	282	295	343	349
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
N_2O	**685**	**722**	**738**	**732**	**734**	**738**	**718**
Agricultural Soil Management	638	667	682	674	675	680	660

Manure Management	47	55	56	58	58	58	58
Field Burning of Agricultural Residues	+	+	+	+	+	+	+

+ Less than 0.5 Gg.

Note: Totals may not sum due to independent rounding.

6.1. Enteric Fermentation (IPCC Source Category 4A)

Methane is produced as part of normal digestive processes in animals. During digestion, microbes resident in an animal's digestive system ferment food consumed by the animal. This microbial fermentation process, referred to as enteric fermentation, produces CH_4 as a byproduct, which can be exhaled or eructated by the animal. The amount of CH_4 produced and emitted by an individual animal depends primarily upon the animal's digestive system, and the amount and type of feed it consumes.

Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH_4 because of their unique digestive system. Ruminants possess a rumen, or large "fore-stomach," in which microbial fermentation breaks down the feed they consume into products that can be absorbed and metabolized. The microbial fermentation that occurs in the rumen enables them to digest coarse plant material that non-ruminant animals cannot. Ruminant animals, consequently, have the highest CH_4 emissions among all animal types.

Non-ruminant animals (e.g., swine, horses, and mules) also produce CH_4 emissions through enteric fermentation, although this microbial fermentation occurs in the large intestine. These non-ruminants emit significantly less CH_4 on a per-animal basis than ruminants because the capacity of the large intestine to produce CH_4 is lower.

In addition to the type of digestive system, an animal's feed quality and feed intake also affect CH_4 emissions. In general, lower feed quality and/or higher feed intake leads to higher CH_4 emissions. Feed intake is positively correlated to animal size, growth rate, and production (e.g., milk production, wool growth, pregnancy, or work). Therefore, feed intake varies among animal types as well as among different management practices for individual animal types (e.g., animals in feedlots or grazing on pasture).

Methane emission estimates from enteric fermentation are provided in Table 6-3 and Table 6-4. Total livestock CH_4 emissions in 2009 were 139.8 Tg CO_2 Eq. (6,655 Gg). Beef cattle remain the largest contributor of CH_4 emissions from enteric fermentation, accounting for 71 percent in 2009. Emissions from dairy cattle in 2009 accounted for 24 percent, and the remaining emissions were from horses, sheep, swine, and goats.

From 1990 to 2009, emissions from enteric fermentation have increased by 5.8 percent. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations have undergone increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations again decreased. During the timeframe of this analysis, populations of sheep have decreased 49 percent while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.

Table 6-3: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Beef Cattle	94.5	100.6	99.3	100.9	101.6	100.7	99.6
Dairy Cattle	31.8	30.7	30.4	31.1	32.4	32.9	33.2
Horses	1.9	2.0	3.5	3.6	3.6	3.6	3.6
Sheep	1.9	1.2	1.0	1.0	1.0	1.0	1.0
Swine	1.7	1.9	1.9	1.9	2.1	2.1	2.1
Goats	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**132.1**	**136.5**	**136.5**	**138.8**	**141.0**	**140.6**	**139.8**

Note: Totals may not sum due to independent rounding.

Table 6-4: CH_4 Emissions from Enteric Fermentation (Gg)

Livestock Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Beef Cattle	4,502	4,790	4,731	4,803	4,837	4,796	4,742
Dairy Cattle	1,513	1,460	1,449	1,479	1,544	1,564	1,581

Horses	91		94		166	171	171	171	171
Sheep	91		56		49	50	49	48	46
Swine	81		88		92	93	98	101	99
Goats	13		12		14	15	16	16	16
Total	**6,290**		**6,502**		**6,500**	**6,611**	**6,715**	**6,696**	**6,655**

Note: Totals may not sum due to independent rounding.

Methodology

Livestock emission estimate methodologies fall into two categories: cattle and other domesticated animals. Cattle, due to their large population, large size, and particular digestive characteristics, account for the majority of CH_4 emissions from livestock in the United States. A more detailed methodology (i.e., IPCC Tier 2) was therefore applied to estimate emissions for all cattle except for bulls. Emission estimates for other domesticated animals (horses, sheep, swine, goats, and bulls) were handled using a less detailed approach (i.e., IPCC Tier 1).

While the large diversity of animal management practices cannot be precisely characterized and evaluated, significant scientific literature exists that provides the necessary data to estimate cattle emissions using the IPCC Tier 2 approach. The Cattle Enteric Fermentation Model (CEFM), developed by EPA and used to estimate cattle CH_4 emissions from enteric fermentation, incorporates this information and other analyses of livestock population, feeding practices, and production characteristics.

National cattle population statistics were disaggregated into the following cattle sub-populations:

- Dairy Cattle
    - Calves
    - Heifer Replacements
    - Cows
- Beef Cattle
    - Calves
    - Heifer Replacements
    - Heifer and Steer Stockers
    - Animals in Feedlots (Heifers and Steers)
    - Cows
    - Bulls

Calf birth rates, end-of-year population statistics, detailed feedlot placement information, and slaughter weight data were used to create a transition matrix that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Annex 3.9. These variables include performance factors such as pregnancy and lactation as well as average weights and weight gain. Annual cattle population data were obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service (NASS) QuickStats database (USDA 2010).

Diet characteristics were estimated by region for U.S. dairy, beef, and feedlot cattle. These estimates were used to calculate Digestible Energy (DE) values (expressed as the percent of gross energy intake digested by the animal) and CH_4 conversion rates (Y_m) (expressed as the fraction of gross energy converted to CH_4) for each population category. The IPCC recommends Y_m values of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for other well-fed cattle consuming temperate-climate feed types (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, DE and Y_m values unique to the United States were developed, rather than using the recommended IPCC values. The diet characterizations and estimation of DE and Y_m values were based on information from state agricultural extension specialists, a review of published forage quality studies and scientific literature, expert opinion, and modeling of animal physiology. The diet characteristics for dairy cattle were based on Donovan (1999) and an extensive review of nearly 20 years of literature. Dairy replacement heifer diet assumptions were based on the observed relationship in the literature between dairy cow and dairy heifer diet characteristics. The diet assumptions for beef cattle were derived from NRC (2000). For feedlot animals, the DE and Y_m values used for 1990 were recommended by Johnson (1999). Values for DE and Y_m for 1991 through 1999 were linearly extrapolated based on the 1990 and 2000 data. DE and Y_m values for 2000 onwards were based on survey data in Galyean and Gleghorn (2001) and Vasconcelos and Galyean (2007). For grazing beef cattle, DE values were based on diet information in NRC (2000) and Y_m values were based on Johnson (2002). Weight and weight gains for cattle were estimated from Holstein Association USA (2010), Enns (2008), Lippke et al. (2000), Pinchack et al., (2004), Platter et al. (2003), Skogerboe et al. (2000), and expert opinion. See Annex 3.9 for more details on the method used to characterize cattle diets and weights in the United States.

To estimate CH_4 emissions from all cattle types except bulls and calves younger than 7 months,[139] the population was divided into state, age, sub-type (i.e., dairy cows and replacements, beef cows and replacements, heifer and steer stockers, and heifers and steers in feedlots), and production (i.e., pregnant, lactating) groupings to more fully capture differences in CH_4 emissions from these animal types. The transition matrix was used to simulate the age and weight structure of each sub-type on a monthly basis, to more accurately reflect the fluctuations that occur throughout the year. Cattle diet characteristics were then used in conjunction with Tier 2 equations from IPCC (2006) to produce CH_4 emission factors for the following cattle types: dairy cows, beef cows, dairy replacements, beef replacements, steer stockers, heifer stockers, steer feedlot animals, and heifer feedlot animals. To estimate emissions from cattle, population data from the transition matrix were multiplied by the calculated emission factor for each cattle type. More details are provided in Annex 3.9.

Emission estimates for other animal types were based on average emission factors representative of entire populations of each animal type. Methane emissions from these animals accounted for a minor portion of total CH_4 emissions from livestock in the United States from 1990 through 2009. Also, the variability in emission factors for each of these other animal types (e.g., variability by age, production system, and feeding practice within each animal type) is less than that for cattle. Annual livestock population data for these other livestock types, except horses and goats, as well as feedlot placement information, were obtained for all years from USDA NASS (USDA 2010). Horse population data were obtained from the Food and Agriculture Organization of the United Nations (FAO) FAOSTAT database (FAO 2010), because USDA does not estimate U.S. horse populations annually. Goat population data were obtained for 1992, 1997, 2002, and 2007 (USDA 2010); these data were interpolated and extrapolated to derive estimates for the other years. Methane emissions from sheep, goats, swine, and horses were estimated by using emission factors utilized in Crutzen et al. (1986, cited in IPCC 2006). These emission factors are representative of typical animal sizes, feed intakes, and feed characteristics in developed countries. The methodology is the same as that recommended by IPCC (2006).

See Annex 3.9 for more detailed information on the methodology and data used to calculate CH_4 emissions from enteric fermentation.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis for this source category was performed through the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique as described in ICF (2003). These uncertainty estimates were developed for the 1990 through 2001 Inventory report. No significant changes occurred in the method of data collection, data estimation methodology, or other factors that influence the uncertainty ranges around the 2009 activity data and emission factor input variables used in the current submission. Consequently, these uncertainty estimates were directly applied to the 2009 emission estimates.

A total of 185 primary input variables (177 for cattle and 8 for non-cattle) were identified as key input variables for the uncertainty analysis. A normal distribution was assumed for almost all activity- and emission factor-related input variables. Triangular distributions were assigned to three input variables (specifically, cow-birth ratios for the three most recent years included in the 2001 model run) to capture the fact that these variables cannot be negative. For some key input variables, the uncertainty ranges around their estimates (used for inventory estimation) were collected from published documents and other public sources; others were based on expert opinion and best estimates. In addition, both endogenous and exogenous correlations between selected primary input variables were

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[139] Emissions from bulls are estimated using a Tier 1 approach because it is assumed there is minimal variation in population and diets. Because calves younger than 7 months consume mainly milk and the IPCC recommends the use of methane conversion factor of zero for all juveniles consuming only milk, this results in no methane emissions from this subcategory of cattle.

modeled. The exogenous correlation coefficients between the probability distributions of selected activity-related variables were developed through expert judgment.

The uncertainty ranges associated with the activity data-related input variables were plus or minus 10 percent or lower. However, for many emission factor-related input variables, the lower- and/or the upper-bound uncertainty estimates were over 20 percent. The results of the quantitative uncertainty analysis are summarized in Table 6-5. Enteric fermentation CH_4 emissions in 2009 were estimated to be between 124.4 and 165.0 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 11 percent below to 18 percent above the 2009 emission estimate of 139.8 Tg CO_2 Eq. Among the individual cattle sub-source categories, beef cattle account for the largest amount of CH_4 emissions as well as the largest degree of uncertainty in the inventory emission estimates. Among non-cattle, horses account for the largest degree of uncertainty in the inventory emission estimates because there is a higher degree of uncertainty among the FAO population estimates used for horses than for the USDA population estimates used for swine, goats, and sheep.

Table 6-5: Quantitative Uncertainty Estimates for CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a, b] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Enteric Fermentation	CH_4	139.8	124.4	165.0	-11%	+18%

[a] Range of emissions estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

[b] Note that the relative uncertainty range was estimated with respect to the 2001 emission estimates submitted in 2003 and applied to the 2009 estimates.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section.

QA/QC and Verification

In order to ensure the quality of the emission estimates from enteric fermentation, the IPCC Tier 1 and Tier 2 Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. QA/QC plan. Tier 2 QA procedures included independent peer review of emission estimates. Because there were no major modifications to the CEFM for 2009, QA/QC emphasis for the current Inventory was placed on cleaning up documentation and references within the model, and review of external data sources. For example, during the course of the QA/QC activities for this source category, it was noted that the U.S. total for 2009 Cattle On Feed data provided via USDA's Quickstats database did not match the total calculated from summing all individual states. The appropriate party was contacted at USDA, and it was determined that data for New Mexico and North Carolina were included individually, as well as within the "Other States" aggregate number, so they were being double counted in the U.S. total. This issue was quickly resolved.

In addition, over the past few years, particular importance has been placed on harmonizing the data exchange between the enteric fermentation and manure management source categories. The current inventory submission now utilizes the transition matrix from the CEFM for estimating cattle populations and weights for both source categories, and the CEFM is used to output volatile solids and nitrogen (N) excretion estimates using the diet assumptions in the model in conjunction with the energy balance equations from the IPCC (2006). This approach should complete the resolution of the discrepancies noted in previous reviews of these sectors, and facilitate the QA/QC process for both of these source categories.

Recalculations Discussion

There were several modifications to the estimates relative to the previous Inventory that had an effect on emission estimates, including the following:

- The average weight assumed for mature dairy cows has changed from the 1,550 pounds used in previous inventories to 1,500 pounds (Johnson 2010; Holstein Association 2010).
- The USDA published revised estimates in several categories that affected historical emissions estimated for

cattle and swine for 2008. Calves, beef replacements, and feedlot cattle all saw slight modifications to their 2008 populations, while swine population categories were modified so that the categories "<60 pounds" and "60-119 pounds" were replaced with "<50 pounds" and "50-119" pounds. Additionally, 2008 lactation estimates for Arkansas, Connecticut, Indiana, Nebraska, New Jersey, Oklahoma, South Carolina, and Vermont were updated by USDA.

- For the 1990 through 2009 inventory, goat population data were taken from the 2007 *Census of Agriculture*. For 2007 population values, the Census's 2007 "Total Goat" population for each state was used. Using the 2002 and 2007 data points, the population for the intervening years was interpolated, and the population for 2008 and 2009 were set equal to the population for 2007. The updated Census data resulted in a change in population values from 2003 through 2008 as populations for these years were previously set equal to the 2002 population.

As a result of these changes, dairy cattle emissions decreased an average of 11.5 Gg (0.8 percent) per year and beef cattle emissions decreased an average of 0.13 Gg (less than 0.01 percent) per year over the entire time series relative to the previous Inventory. Historical emission estimates for 2008 increased by 1.3 percent for goats as a result of the USDA population revisions described above.

Planned Improvements

Continued research and regular updates are necessary to maintain a current model of cattle diet characterization, feedlot placement data, rates of weight gain and calving, among other data inputs. Ongoing revisions could include some of the following options:

- Reviewing and updating the diet assumptions for foraging beef cattle;
- Estimating bull emissions using the IPCC Tier 2 approach;
- Updating input variables that are from older data sources, such as beef births by month and beef cow lactation rates;
- The possible breakout of other animal types (i.e., sheep, swine, goats, horses) from national estimates to state-level estimates; and
- Including bison in the estimates for other domesticated animals.

In addition, recent changes that have been implemented to the CEFM warrant an assessment of the current uncertainty analysis; therefore, a revision of the quantitative uncertainty surrounding emission estimates from this source category will be initiated.

6.2. Manure Management (IPCC Source Category 4B)

The management of livestock manure can produce anthropogenic CH_4 and N_2O emissions. Methane is produced by the anaerobic decomposition of manure. Direct N_2O emissions are produced as part of the N cycle through the nitrification and denitrification of the organic N in livestock dung and urine.[140] Indirect N_2O emissions are produced as result of the volatilization of N as NH_3 and NO_x and runoff and leaching of N during treatment, storage and transportation.

When livestock or poultry manure are stored or treated in systems that promote anaerobic conditions (e.g., as a liquid/slurry in lagoons, ponds, tanks, or pits), the decomposition of materials in the manure tends to produce CH_4. When manure is handled as a solid (e.g., in stacks or drylots) or deposited on pasture, range, or paddock lands, it tends to decompose aerobically and produce little or no CH_4. Ambient temperature, moisture, and manure storage or residency time affect the amount of CH_4 produced because they influence the growth of the bacteria responsible for CH_4 formation. For non-liquid-based manure systems, moist conditions (which are a function of rainfall and

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[140] Direct and indirect N_2O emissions from dung and urine spread onto fields either directly as daily spread or after it is removed from manure management systems (e.g., lagoon, pit, etc.) and from livestock dung and urine deposited on pasture, range, or paddock lands are accounted for and discussed in the Agricultural Soil Management source category within the Agriculture sector.

humidity) can promote CH_4 production. Manure composition, which varies by animal diet, growth rate, and type, including the animal's digestive system, also affects the amount of CH_4 produced. In general, the greater the energy content of the feed, the greater the potential for CH_4 emissions. However, some higher-energy feeds also are more digestible than lower quality forages, which can result in less overall waste excreted from the animal.

The production of direct N_2O emissions from livestock manure depends on the composition of the manure and urine, the type of bacteria involved in the process, and the amount of oxygen and liquid in the manure system. For direct N_2O emissions to occur, the manure must first be handled aerobically where ammonia (NH_3) or organic N is converted to nitrates and nitrites (nitrification), and then handled anaerobically where the nitrates and nitrites are reduced to dinitrogen gas (N_2), with intermediate production of N_2O and nitric oxide (NO) (denitrification) (Groffman et al. 2000). These emissions are most likely to occur in dry manure handling systems that have aerobic conditions, but that also contain pockets of anaerobic conditions due to saturation. A very small portion of the total N excreted is expected to convert to N_2O in the waste management system (WMS). Indirect N_2O emissions are produced when nitrogen is lost from the system through volatilization (as NH_3 or NO_x) or through runoff and leaching. The vast majority of volatilization losses from these operations are NH_3. Although there are also some small losses of NO_x, there are no quantified estimates available for use, so losses due to volatilization are only based on NH_3 loss factors. Runoff losses would be expected from operations that house animals or store manure in a manner that is exposed to weather. Runoff losses are also specific to the type of animal housed on the operation due to differences in manure characteristics. Little information is known about leaching from manure management systems as most research focuses on leaching from land application systems. Since leaching losses are expected to be minimal, leaching losses are coupled with runoff losses and the runoff/leaching estimate does not include any leaching losses.

Estimates of CH_4 emissions in 2009 were 49.5 Tg CO_2 Eq. (2,356 Gg), 56 percent higher than in 1990. Emissions increased on average by 0.9 Tg CO_2 Eq. (2.5 percent) annually over this period. The majority of this increase was from swine and dairy cow manure, where emissions increased 45 and 95 percent, respectively. Although the majority of manure in the United States is handled as a solid, producing little CH_4, the general trend in manure management, particularly for dairy and swine (which are both shifting towards larger facilities), is one of increasing use of liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site. Although national dairy animal populations have been generally decreasing, some states have seen increases in their dairy populations as the industry becomes more concentrated in certain areas of the country. These areas of concentration, such as California, New Mexico, and Idaho, tend to utilize more liquid-based systems to manage (flush or scrape) and store manure. Thus the shift toward larger facilities is translated into an increasing use of liquid manure management systems, which have higher potential CH_4 emissions than dry systems. This shift was accounted for by incorporating state and WMS-specific CH_4 conversion factor (MCF) values in combination with the 1992, 1997, and 2002 farm-size distribution data reported in the *Census of Agriculture* (USDA 2009a). Methane emissions from sheep have decreased significantly since 1990 (a 54 percent decrease from 1990 to 2009); however, this is mainly due to population changes. Overall, sheep contribute less than one percent of CH_4 emissions from animal manure management. From 2008 to 2009, there was a less than 1 percent increase in total CH_4 emissions, due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

In 2009, total N_2O emissions were estimated to be 17.9 Tg CO_2 Eq. (58 Gg); in 1990, emissions were 14.5 Tg CO_2 Eq. (47 Gg). These values include both direct and indirect N_2O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N_2O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N_2O emissions showed a 23 percent increase from 1990 to 2009 and a less than 1 percent decrease from 2008 through 2009.

Table 6-6 and Table 6-7 provide estimates of CH_4 and N_2O emissions from manure management by animal category.

Table 6-6: CH_4 and N_2O Emissions from Manure Management (Tg CO_2 Eq.)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH_4[a]	**31.7**	**42.4**	**46.6**	**46.7**	**50.7**	**49.4**	**49.5**
Dairy Cattle	12.6	18.9	21.4	21.7	24.2	24.1	24.5
Beef Cattle	2.7	2.8	2.8	2.9	2.9	2.8	2.7
Swine	13.1	17.5	19.0	18.7	20.3	19.3	19.0
Sheep	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Goats	+	+	+	+	+	+	+
Poultry	2.8	2.7	2.7	2.7	2.8	2.7	2.7
Horses	0.5	0.4	0.6	0.6	0.6	0.5	0.5
N_2O^b	**14.5**	**17.1**	**17.3**	**18.0**	**18.1**	**17.9**	**17.9**
Dairy Cattle	5.3	5.6	5.6	5.8	5.8	5.7	5.8
Beef Cattle	6.1	7.8	7.5	8.0	7.9	7.8	7.8
Swine	1.2	1.6	1.8	1.8	1.9	2.0	2.0
Sheep	0.1	0.3	0.4	0.4	0.4	0.4	0.3
Goats	+	+	+	+	+	+	+
Poultry	1.5	1.6	1.7	1.7	1.7	1.7	1.6
Horses	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Total	**46.2**	**59.5**	**63.8**	**64.8**	**68.9**	**67.3**	**67.3**

+ Less than 0.05 Tg CO_2 Eq.

[a] Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.

[b] Includes both direct and indirect N_2O emissions.

Note: Totals may not sum due to independent rounding.

Table 6-7: CH_4 and N_2O Emissions from Manure Management (Gg)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH_4^a	**1,511**	**2,019**	**2,217**	**2,226**	**2,416**	**2,353**	**2,356**
Dairy Cattle	599	900	1,018	1,034	1,151	1,147	1,168
Beef Cattle	128	133	132	139	136	131	130
Swine	624	834	905	889	965	918	903
Sheep	7	4	3	3	3	3	3
Goats	1	1	1	1	1	1	1
Poultry	131	127	129	131	134	129	127
Horses	22	20	28	28	27	24	24
N_2O^b	**47**	**55**	**56**	**58**	**58**	**58**	**58**
Dairy Cattle	17	18	18	19	19	18	19
Beef Cattle	20	25	24	26	26	25	25
Swine	4	5	6	6	6	6	6
Sheep	+	1	1	1	1	1	1
Goats	+	+	+	+	+	+	+
Poultry	5	5	5	5	5	5	5
Horses	1	1	1	1	1	1	1

+ Less than 0.5 Gg.

[a] Accounts for CH_4 reductions due to capture and destruction of CH_4 at facilities using anaerobic digesters.

[b] Includes both direct and indirect N_2O emissions.

Note: Totals may not sum due to independent rounding.

Methodology

The methodologies presented in IPCC (2006) form the basis of the CH_4 and N_2O emission estimates for each animal type. This section presents a summary of the methodologies used to estimate CH_4 and N_2O emissions from manure management for this Inventory. See Annex 3.10 for more detailed information on the methodology and data used to calculate CH_4 and N_2O emissions from manure management.

Methane Calculation Methods

The following inputs were used in the calculation of CH_4 emissions:

- Animal population data (by animal type and state);
- Typical animal mass (TAM) data (by animal type);
- Portion of manure managed in each waste management system (WMS), by state and animal type;
- Volatile solids (VS) production rate (by animal type and state or United States);
- Methane producing potential (B_o) of the volatile solids (by animal type); and

- Methane conversion factors (MCF), the extent to which the CH_4 producing potential is realized for each type of WMS (by state and manure management system, including the impacts of any biogas collection efforts).

Methane emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources are described below:

- Annual animal population data for 1990 through 2009 for all livestock types, except horses and goats were obtained from USDA NASS. For cattle, the USDA populations were utilized in conjunction with birth rates, detailed feedlot placement information, and slaughter weight data to create the transition matrix in the CEFM that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Section 6.1 and in more detail in Annex 3.9. Horse population data were obtained from the FAOSTAT database (FAO 2010). Goat population data for 1992, 1997, 2002, and 2007 were obtained from the *Census of Agriculture* (USDA 2009a).
- The TAM is an annual average weight which was obtained for animal types other than cattle from information in USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a), the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1999) and others (EPA 1992, Safley 2000, ERG 2010a). For a description of the TAM used for cattle, please see section 6.1, Enteric Fermentation.
- WMS usage was estimated for swine and dairy cattle for different farm size categories using data from USDA (USDA 1996b, 1998b, 2000a) and EPA (ERG 2000a, EPA 2002a, 2002b). For beef cattle and poultry, manure management system usage data were not tied to farm size but were based on other data sources (ERG 2000a, USDA 2000b, UEP 1999). For other animal types, manure management system usage was based on previous estimates (EPA 1992).
- VS production rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. VS production rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- The maximum CH_4 producing capacity of the VS (B_o) was determined for each animal type based on literature values (Morris 1976, Bryant et al, 1976, Hashimoto 1981, Hashimoto 1984, EPA 1992, Hill 1982, and Hill 1984).
- MCFs for dry systems were set equal to default IPCC factors based on state climate for each year (IPCC 2006). MCFs for liquid/slurry, anaerobic lagoon, and deep pit systems were calculated based on the forecast performance of biological systems relative to temperature changes as predicted in the van't Hoff-Arrhenius equation which is consistent with IPCC (2006) Tier 2 methodology.
- Anaerobic digestion system data were obtained from the EPA AgSTAR Program, including information presented in the *AgSTAR Digest* (EPA 2000, 2003, 2006). Anearobic digester emissions were calculated based on estimated methane production and collection and destruction efficiency assumptions (ERG 2008).

To estimate CH_4 emissions for cattle, the estimated amount of VS (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the annual amount of VS (kg per year) from manure excreted in each WMS was calculated for each animal type, state, and year. This calculation multiplied the animal population (head) by the VS excretion rate (kg VS per 1,000 kg animal mass per day), the TAM (kg animal mass per head) divided by 1,000, the WMS distribution (percent), and the number of days per year (365.25).

The estimated amount of VS managed in each WMS was used to estimate the CH_4 emissions (kg CH_4 per year) from each WMS. The amount of VS (kg per year) were multiplied by the maximum CH_4 producing capacity of the VS (B_o) (m^3 CH_4 per kg VS), the MCF for that WMS (percent), and the density of CH_4 (kg CH_4 per m^3 CH_4). The CH_4 emissions for each WMS, state, and animal type were summed to determine the total U.S. CH_4 emissions.

Nitrous Oxide Calculation Methods

The following inputs were used in the calculation of direct and indirect N_2O emissions:

- Animal population data (by animal type and state);

- TAM data (by animal type);
- Portion of manure managed in each WMS (by state and animal type);
- Total Kjeldahl N excretion rate (Nex);
- Direct N_2O emission factor (EF_{WMS});
- Indirect N_2O emission factor for volitalization ($EF_{volitalization}$);
- Indirect N_2O emission factor for runoff and leaching ($EF_{runoff/leach}$);
- Fraction of nitrogen loss from volitalization of NH_3 and NO_x ($Frac_{gas}$); and
- Fraction of nitrogen loss from runoff and leaching ($Frac_{runoff/leach}$).

N_2O emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources (except for population, TAM, and WMS, which were described above) are described below:

- Nex rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. Nex rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- All N_2O emission factors (direct and indirect) were taken from IPCC (2006).
- Country-specific estimates for the fraction of N loss from volatilization ($Frac_{gas}$) and runoff and leaching ($Frac_{runoff/leach}$) were developed. $Frac_{gas}$ values were based on WMS-specific volatilization values as estimated from EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). $Frac_{runoff/leaching}$ values were based on regional cattle runoff data from EPA's Office of Water (EPA 2002b; see Annex 3.1).

To estimate N_2O emissions for cattle, the estimated amount of N excreted (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the amount of N excreted (kg per year) in manure in each WMS for each animal type, state, and year was calculated. The population (head) for each state and animal was multiplied by TAM (kg animal mass per head) divided by 1,000, the nitrogen excretion rate (Nex, in kg N per 1000 kg animal mass per day), WMS distribution (percent), and the number of days per year.

Direct N_2O emissions were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the N_2O direct emission factor for that WMS (EF_{WMS}, in kg N_2O-N per kg N) and the conversion factor of N_2O-N to N_2O. These emissions were summed over state, animal, and WMS to determine the total direct N_2O emissions (kg of N_2O per year).

Next, indirect N_2O emissions from volatilization (kg N_2O per year) were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through volatilization ($Frac_{tas}$) divided by 100, and the emission factor for volatilization ($EF_{volatilization}$, in kg N_2O per kg N), and the conversion factor of N_2O-N to N_2O. Indirect N_2O emissions from runoff and leaching (kg N_2O per year) were then calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through runoff and leaching ($Frac_{runoff/leach}$) divided by 100, and the emission factor for runoff and leaching ($EF_{runoff/leach}$, in kg N_2O per kg N), and the conversion factor of N_2O-N to N_2O. The indirect N_2O emissions from volatilization and runoff and leaching were summed to determine the total indirect N_2O emissions.

The direct and indirect N_2O emissions were summed to determine total N_2O emissions (kg N_2O per year).

Uncertainty and Time-Series Consistency

An analysis (ERG 2003) was conducted for the manure management emission estimates presented in the 1990 through 2001 Inventory report to determine the uncertainty associated with estimating CH_4 and N_2O emissions from livestock manure management. The quantitative uncertainty analysis for this source category was performed in 2002 through the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The uncertainty analysis was developed based on the methods used to estimate CH_4 and N_2O emissions from manure management systems. A normal probability distribution was assumed for each source data category. The series of equations used were condensed into a single equation for each animal type and state. The equations for each animal group contained four to five variables around which the uncertainty analysis was performed for each state. These uncertainty estimates were directly applied to the 2009 emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-8. Manure management CH_4 emissions in 2009 were estimated to be between 40.6 and 59.4 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 18 percent below to 20 percent above the actual 2009 emission estimate of 49.5 Tg CO_2 Eq. At the 95 percent confidence level, N_2O emissions were estimated to be between 15.0 and 22.1 Tg CO_2 Eq. (or approximately 16 percent below and 24 percent above the actual 2009 emission estimate of 17.9 Tg CO_2 Eq.).

Table 6-8: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O (Direct and Indirect) Emissions from Manure Management (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Manure Management	CH_4	49.5	40.6	59.4	-18%	+20%
Manure Management	N_2O	17.9	15.0	22.1	-16%	+24%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Tier 2 activities focused on comparing estimates for the previous and current inventories for N_2O emissions from managed systems and CH_4 emissions from livestock manure. All errors identified were corrected. Order of magnitude checks were also conducted, and corrections made where needed. Manure N data were checked by comparing state-level data with bottom up estimates derived at the county level and summed to the state level. Similarly, a comparison was made by animal and WMS type for the full time series, between national level estimates for nitrogen excreted and the sum of county estimates for the full time series.

Recalculations Discussion

The CEFM produces VS and Nex data for cattle that are used in the manure management inventory. As a result, all changes to the CEFM described in Section 6.1 Enteric Fermentation contributed to changes in the VS and Nex data utilized for calculating CH_4 and N_2O emissions from manure management. In addition, to standardize the estimates of TAM between the CEFM and the manure management source category, the total VS and Nex estimates in units of kg per head per year from the CEFM were used in the manure management calculations in the current Inventory. With these changes, CH_4 and N_2O emission estimates from manure management systems are higher than reported in the previous Inventory for both beef and dairy cattle. Methane emissions from beef and dairy cattle were higher by 7 and 24 percent, respectively, while N_2O emissions were higher by 1 and 5 percent for beef and dairy cattle, respectively, averaged over the 1990 to 2008 time series.

In addition to changes in cattle Nex and VS data, the VS and Nex for other animal types were updated using data from USDA's updated *Agricultural Waste Management Field Handbook* (USDA 2008). Data from both the previous *Handbook* and the updated the *Handbook* were used to create a time series of VS and Nex data across all inventory years for all animals (ERG 2010b). The VS and Nex updates for all animals contributed to an average emission increase of 9.5 percent for CH_4 and 2.7 percent for N_2O across the time series.

For the current Inventory, USDA population data were used that included updated market swine categories. USDA changed the "market swine under 60 lbs." category to "market swine under 50 lbs." for years 2008 and 2009. In addition, USDA changed the "market swine from 60-119 lbs." to "market swine from 50-119 lbs." for the same years. This update resulted in a change in TAM estimates for those two swine categories which contributed to an overall decrease in CH_4 emissions from swine of 1.6 percent and an overall increase in N_2O emissions from swine of 20.9 percent in 2008.

The goat population was updated to reflect the USDA 2007 Census of Agriculture. This change resulted in an increase in both $CH_4$and N_2O emissions for goats from the years 2003 through 2008 by 13 percent and 16 percent on average, respectively.

Planned Improvements

A recent journal article (Lory et al., 2010) criticized the IPCC and EPA methodology used to estimate greenhouse gas emissions from manure management. After review of the methodologies, EPA does not feel that any changes to the IPCC inventory methodologies are required as a result of this article; for more specific information, please see EPA's detailed response to the article (Bartram et al., 2010). EPA will continue to investigate any new or additional data sources identified that contain updated information that can be used to improve the inventory emission estimates. Also, EPA will continue to seek empirical data to compare inventory estimates to specific systems, in order to improve the methodology used to estimate greenhouse gas emissions from manure management.

USDA's 2007 *Census of Agriculture* data are finalized and available. These data will be incorporated into the county-level population estimates used for the Agricultural Soils source category and the estimates of MCF and utilize it to update the WMS distributions for swine and dairy animals.

Due to time constraints, the temperature data used to estimate MCFs were not updated for the current Inventory. Updated temperature data will be obtained and applied for subsequent Inventory reports.

The uncertainty analysis will be updated in the future to more accurately assess uncertainty of emission calculations. This update is necessary due to the extensive changes in emission calculation methodology that was made in the 1990 through 2006 Inventory, including estimation of emissions at the WMS level and the use of new calculations and variables for indirect N_2O emissions.

6.3. Rice Cultivation (IPCC Source Category 4C)

Most of the world's rice, and all rice in the United States, is grown on flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, CH_4 is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. As much as 60 to 90 percent of the CH_4 produced is oxidized by aerobic methanotrophic bacteria in the soil (some oxygen remains at the interfaces of soil and water, and soil and root system) (Holzapfel-Pschorn et al. 1985, Sass et al. 1990). Some of the CH_4 is also leached away as dissolved CH_4 in floodwater that percolates from the field. The remaining un-oxidized CH_4 is transported from the submerged soil to the atmosphere primarily by diffusive transport through the rice plants. Minor amounts of CH_4 also escape from the soil via diffusion and bubbling through floodwaters.

The water management system under which rice is grown is one of the most important factors affecting CH_4 emissions. Upland rice fields are not flooded, and therefore are not believed to produce CH_4. In deepwater rice fields (i.e., fields with flooding depths greater than one meter), the lower stems and roots of the rice plants are dead, so the primary CH_4 transport pathway to the atmosphere is blocked. The quantities of CH_4 released from deepwater fields, therefore, are believed to be significantly less than the quantities released from areas with shallower flooding depths. Some flooded fields are drained periodically during the growing season, either intentionally or accidentally. If water is drained and soils are allowed to dry sufficiently, CH_4 emissions decrease or stop entirely. This is due to soil aeration, which not only causes existing soil CH_4 to oxidize but also inhibits further CH_4 production in soils. All rice in the United States is grown under continuously flooded conditions; none is grown under deepwater conditions. Mid-season drainage does not occur except by accident (e.g., due to levee breach).

Other factors that influence CH_4 emissions from flooded rice fields include fertilization practices (especially the use of organic fertilizers), soil temperature, soil type, rice variety, and cultivation practices (e.g., tillage, seeding, and weeding practices). The factors that determine the amount of organic material available to decompose (i.e., organic fertilizer use, soil type, rice variety,[141] and cultivation practices) are the most important variables influencing the amount of CH_4 emitted over the growing season; the total amount of CH_4 released depends primarily on the amount of organic substrate available. Soil temperature is known to be an important factor regulating the activity of methanogenic bacteria, and therefore the rate of CH_4 production. However, although temperature controls the amount of time it takes to convert a given amount of organic material to CH_4, that time is short relative to a growing season, so the dependence of total emissions over an entire growing season on soil temperature is weak. The application of synthetic fertilizers has also been found to influence CH_4 emissions; in particular, both nitrate and

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[141] The roots of rice plants shed organic material, which is referred to as "root exudate." The amount of root exudate produced by a rice plant over a growing season varies among rice varieties.

sulfate fertilizers (e.g., ammonium nitrate and ammonium sulfate) appear to inhibit CH_4 formation.

Rice is cultivated in eight states: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, Oklahoma, and Texas.[142] Soil types, rice varieties, and cultivation practices for rice vary from state to state, and even from farm to farm. However, most rice farmers apply organic fertilizers in the form of residue from the previous rice crop, which is left standing, disked, or rolled into the fields. Most farmers also apply synthetic fertilizer to their fields, usually urea. Nitrate and sulfate fertilizers are not commonly used in rice cultivation in the United States. In addition, the climatic conditions of southwest Louisiana, Texas, and Florida often allow for a second, or ratoon, rice crop. Ratoon crops are much less common or non-existent in Arkansas, California, Mississippi, Missouri, Oklahoma, and northern areas of Louisiana. Methane emissions from ratoon crops have been found to be considerably higher than those from the primary crop. This second rice crop is produced from regrowth of the stubble after the first crop has been harvested. Because the first crop's stubble is left behind in ratooned fields, and there is no time delay between cropping seasons (which would allow the stubble to decay aerobically), the amount of organic material that is available for anaerobic decomposition is considerably higher than with the first (i.e., primary) crop.

Rice cultivation is a small source of CH_4 in the United States (Table 6-9 and Table 6-10). In 2009, CH_4 emissions from rice cultivation were 7.3 Tg CO_2 Eq. (349 Gg). Annual emissions fluctuated unevenly between the years 1990 and 2009, ranging from an annual decrease of 14 percent to an annual increase of 17 percent. There was an overall decrease of 17 percent between 1990 and 2006, due to an overall decrease in primary crop area.[143] However, emission levels increased again by 24 percent between 2006 and 2009 due to a slight increase in rice crop area in all states. The factors that affect the rice acreage in any year vary from state to state, although the price of rice relative to competing crops is the primary controlling variable in most states.

Table 6-9: CH_4 Emissions from Rice Cultivation (Tg CO_2 Eq.)

State	1990	2000	2005	2006	2007	2008	2009
Primary	**5.1**	**5.5**	**6.0**	**5.1**	**4.9**	**5.3**	**5.6**
Arkansas	2.1	2.5	2.9	2.5	2.4	2.5	2.6
California	0.7	1.0	0.9	0.9	1.0	0.9	1.0
Florida	+	+	+	+	+	+	+
Louisiana	1.0	0.9	0.9	0.6	0.7	0.8	0.8
Mississippi	0.4	0.4	0.5	0.3	0.3	0.4	0.4
Missouri	0.1	0.3	0.4	0.4	0.3	0.4	0.4
Oklahoma	+	+	+	+	0.0	0.0	0.0
Texas	0.6	0.4	0.4	0.3	0.3	0.3	0.3
Ratoon	**2.1**	**2.0**	**0.8**	**0.9**	**1.3**	**1.9**	**1.8**
Arkansas	+	+	+	+	+	+	+
Florida	+	0.1	+	+	+	+	+
Louisiana	1.1	1.3	0.5	0.5	0.9	1.2	1.1
Texas	0.9	0.7	0.4	0.4	0.3	0.6	0.7
Total	**7.1**	**7.5**	**6.8**	**5.9**	**6.2**	**7.2**	**7.3**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 6-10: CH_4 Emissions from Rice Cultivation (Gg)

State	1990	2000	2005	2006	2007	2008	2009
Primary	**241**	**260**	**287**	**241**	**235**	**254**	**265**
Arkansas	102	120	139	119	113	119	125
California	34	47	45	44	45	44	47
Florida	1	2	1	1	1	1	1
Louisiana	46	41	45	29	32	39	39

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[142] A very small amount of rice is grown on about 20 acres in South Carolina; however, this amount was determined to be too insignificant to warrant inclusion in national emission estimates.

[143] The 14 percent decrease occurred between 2005 and 2006; the 17 percent increase happened between 1993 and 1994.

Mississippi	21	19	22	16	16	19	21
Missouri	7	14	18	18	15	17	17
Oklahoma	+	+	+	+	0	+	+
Texas	30	18	17	13	12	15	14
Ratoon	**98**	**97**	**39**	**41**	**60**	**89**	**84**
Arkansas	+	+	1	+	+	+	+
Florida	2	2	+	1	1	1	2
Louisiana	52	61	22	22	42	59	51
Texas	45	34	17	18	16	29	31
Total	**339**	**357**	**326**	**282**	**295**	**343**	**349**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

IPCC (2006) recommends using harvested rice areas, area-based daily emission factors (i.e., amount of CH_4 emitted per day per unit harvested area), and length of growing season to estimate annual CH_4 emissions from rice cultivation. This Inventory uses the recommended methodology and employs Tier 2 U.S.-specific emission factors derived from rice field measurements. State-specific and daily emission factors were not available, however, so average U.S. seasonal emission factors were used. Seasonal emissions have been found to be much higher for ratooned crops than for primary crops, so emissions from ratooned and primary areas are estimated separately using emission factors that are representative of the particular growing season. This approach is consistent with IPCC (2006).

The harvested rice areas for the primary and ratoon crops in each state are presented in Table 6-11, and the area of ratoon crop area as a percent of primary crop area is shown in Table 6-12. Primary crop areas for 1990 through 2009 for all states except Florida and Oklahoma were taken from U.S. Department of Agriculture's Field Crops Final Estimates 1987–1992 (USDA 1994), Field Crops Final Estimates 1992–1997 (USDA 1998), Field Crops Final Estimates 1997–2002 (USDA 2003), and Crop Production Summary (USDA 2005 through 2010). Source data for non-USDA sources of primary and ratoon harvest areas are shown in Table 6-13. California, Mississippi, Missouri, and Oklahoma have not ratooned rice over the period 1990 through 2009 (Guethle 1999 through 2010; Lee 2003 through 2007; Mutters 2002 through 2005; Street 1999 through 2003; Walker 2005, 2007 through 2008; Buehring 2009 through 2010).

Table 6-11: Rice Areas Harvested (Hectares)

State/Crop	1990	2000	2005	2006	2007	2008	2009
Arkansas							
Primary	485,633	570,619	661,675	566,572	536,220	564,549	594,901
Ratoon[a]	-	-	662	6	5	6	6
California	159,854	221,773	212,869	211,655	215,702	209,227	225,010
Florida							
Primary	4,978	7,801	4,565	4,575	6,242	5,463	5,664
Ratoon	2,489	3,193	0	1,295	1,873	1,639	2,266
Louisiana							
Primary	220,558	194,253	212,465	139,620	152,975	187,778	187,778
Ratoon	66,168	77,701	27,620	27,924	53,541	75,111	65,722
Mississippi	101,174	88,223	106,435	76,487	76,487	92,675	98,341
Missouri	32,376	68,393	86,605	86,605	72,036	80,534	80,939
Oklahoma	617	283	271	17	0	77	0
Texas							
Primary	142,857	86,605	81,344	60,704	58,681	69,607	68,798
Ratoon	57,143	43,302	21,963	23,675	21,125	36,892	39,903
Total Primary	***1,148,047***	***1,237,951***	***1,366,228***	***1,146,235***	***1,118,343***	***1,209,911***	***1,261,431***

Total Ratoon	*125,799*		*124,197*		*50,245*	*52,899*	*76,544*	*113,648*	*107,897*
Total	**1,273,847**		**1,362,148**		**1,416,473**	**1,199,135**	**1,194,887**	**1,323,559**	**1,369,328**

[a] Arkansas ratooning occurred only in 1998, 1999, and 2005 through 2009.

Note: Totals may not sum due to independent rounding.

Table 6-12: Ratooned Area as Percent of Primary Growth Area

State	**1990**		**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Arkansas	0%			+	+	0%					0.1%	+	+	+	+
Florida	50%				65%	41%	60%	54%	100%	77%	0%	28%	30%	30%	40%
Louisiana	30%					40%	30%	15%	35%	30%	13%	20%	35%	40%	35%
Texas	40%					50%	40%	37%	38%	35%	27%	39%	36%	53%	58%

+ Indicates ratooning rate less than 0.1 percent.

Table 6-13: Non-USDA Data Sources for Rice Harvest Information

State/Crop	**1990**		**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Arkansas												
Ratoon	Wilson (2002 – 2007, 2009 – 2010)											
Florida												
Primary	Scheuneman (1999 – 2001)			Deren (2002)	Kirstein (2003, 2006)			Gonzales (2006 – 2010)				
Ratoon	Scheuneman (1999)			Deren (2002)	Kirstein (2003-2004)		Cantens (2005)	Gonzales (2006 – 2010)				
Louisiana												
Ratoon	Bollich (2000)		Linscombe (1999, 2001 – 2010)									
Oklahoma												
Primary	Lee (2003-2007)									Anderson (2008 – 2010)		
Texas												
Ratoon	Klosterboer (1999 – 2003)					Stansel (2004 – 2005)		Texas Ag Experiment Station (2006 – 2010)				

To determine what CH_4 emission factors should be used for the primary and ratoon crops, CH_4 flux information from rice field measurements in the United States was collected. Experiments that involved atypical or nonrepresentative management practices (e.g., the application of nitrate or sulfate fertilizers, or other substances believed to suppress CH_4 formation), as well as experiments in which measurements were not made over an entire flooding season or floodwaters were drained mid-season, were excluded from the analysis. The remaining experimental results[144] were then sorted by season (i.e., primary and ratoon) and type of fertilizer amendment (i.e., no fertilizer added, organic fertilizer added, and synthetic and organic fertilizer added). The experimental results from primary crops with added synthetic and organic fertilizer (Bossio et al. 1999; Cicerone et al. 1992; Sass et al. 1991a, 1991b) were averaged to derive an emission factor for the primary crop, and the experimental results from ratoon crops with added synthetic fertilizer (Lindau and Bollich 1993, Lindau et al. 1995) were averaged to derive an emission factor for the ratoon crop. The resultant emission factor for the primary crop is 210 kg CH_4/hectare-season, and the resultant emission factor for the ratoon crop is 780 kg CH_4/hectare-season.

Uncertainty and Time-Series Consistency

The largest uncertainty in the calculation of CH_4 emissions from rice cultivation is associated with the emission factors. Seasonal emissions, derived from field measurements in the United States, vary by more than one order of

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[144] In some of these remaining experiments, measurements from individual plots were excluded from the analysis because of the aforementioned reasons. In addition, one measurement from the ratooned fields (i.e., the flux of 1,490 kg CH_4/hectare-season in Lindau and Bollich 1993) was excluded, because this emission rate is unusually high compared to other flux measurements in the United States, as well as IPCC (2006) default emission factors.

magnitude. This inherent variability is due to differences in cultivation practices, particularly fertilizer type, amount, and mode of application; differences in cultivar type; and differences in soil and climatic conditions. A portion of this variability is accounted for by separating primary from ratooned areas. However, even within a cropping season or a given management regime, measured emissions may vary significantly. Of the experiments used to derive the emission factors applied here, primary emissions ranged from 22 to 479 kg CH_4/hectare-season and ratoon emissions ranged from 481 to 1,490 kg CH_4/hectare-season. The uncertainty distributions around the primary and ratoon emission factors were derived using the distributions of the relevant primary or ratoon emission factors available in the literature and described above. Variability about the rice emission factor means was not normally distributed for either primary or ratooned crops, but rather skewed, with a tail trailing to the right of the mean. A lognormal statistical distribution was, therefore, applied in the Tier 2 Monte Carlo analysis.

Other sources of uncertainty include the primary rice-cropped area for each state, percent of rice-cropped area that is ratooned, and the extent to which flooding outside of the normal rice season is practiced. Expert judgment was used to estimate the uncertainty associated with primary rice-cropped area for each state at 1 to 5 percent, and a normal distribution was assumed. Uncertainties were applied to ratooned area by state, based on the level of reporting performed by the state. No uncertainties were calculated for the practice of flooding outside of the normal rice season because CH_4 flux measurements have not been undertaken over a sufficient geographic range or under a broad enough range of representative conditions to account for this source in the emission estimates or its associated uncertainty.

To quantify the uncertainties for emissions from rice cultivation, a Monte Carlo (Tier 2) uncertainty analysis was performed using the information provided above. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-14. Rice cultivation CH_4 emissions in 2009 were estimated to be between 2.5 and 18.0 Tg CO_2 Eq. at a 95 percent confidence level, which indicates a range of 65 percent below to 146 percent above the actual 2009 emission estimate of 7.3 Tg CO_2 Eq.

Table 6-14: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Rice Cultivation (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Rice Cultivation	CH_4	7.3	2.5	18.0	-65%	+146%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for rice cultivation was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and cropping seasons to attempt to identify any outliers or inconsistencies. No problems were found.

Planned Improvements

A possible future improvement is to create region-specific emission factors for rice cultivation. The current methodology uses a nationwide average emission factor, derived from several studies done in a number of states. The prospective improvement would take the same studies and average them by region, presumably resulting in more spatially specific emission factors.

6.4. Agricultural Soil Management (IPCC Source Category 4D)

Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and denitrification.[145] A number of agricultural activities increase mineral N availability in soils, thereby increasing the amount available for nitrification and denitrification, and ultimately the amount of N_2O emitted. These activities increase soil mineral N either directly or indirectly (see Figure 6-2). Direct increases occur through a variety of management practices that add or lead to greater release of mineral N to the soil, including fertilization; application of managed livestock manure and other organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in pastures, rangelands, and paddocks (PRP) (i.e., by grazing animals and other animals whose manure is not managed); production of N-fixing crops and forages; retention of crop residues; and drainage and cultivation of organic cropland soils (i.e., soils with a high organic matter content, otherwise known as histosols).[146] Other agricultural soil management activities, including irrigation, drainage, tillage practices, and fallowing of land, can influence N mineralization in soils and thereby affect direct emissions. Mineral N is also made available in soils through decomposition of soil organic matter and plant litter, as well as asymbiotic fixation of N from the atmosphere,[147] and these processes are influenced by agricultural management through impacts on moisture and temperature regimes in soils. These additional sources of mineral N are included at the recommendation of IPCC (2006) for complete accounting of management impacts on greenhouse gas emissions, as discussed in the Methodology section. Indirect emissions of N_2O occur through two pathways: (1) volatilization and subsequent atmospheric deposition of applied/mineralized N,[148] and (2) surface runoff and leaching of applied/mineralized N into groundwater and surface water. Direct emissions from agricultural lands (i.e., cropland and grassland) are included in this section, while direct emissions from forest lands and settlements are presented in the Land Use, Land-Use Change, and Forestry chapter. However, indirect N_2O emissions from all land-uses (cropland, grassland, forest lands, and settlements) are reported in this section.

Figure 6-2: Sources and Pathways of N that Result in N_2O Emissions from Agricultural Soil Management

Agricultural soils produce the majority of N_2O emissions in the United States. Estimated emissions from this source in 2009 were 204.6 Tg CO_2 Eq. (660 Gg N_2O) (see Table 6-15 and Table 6-16). Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3 percent higher in 2009 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production. On average, cropland accounted for approximately 70 percent of total direct emissions, while grassland accounted for approximately 30 percent. These percentages are about the same for indirect emissions since forest lands and settlements account for such a small percentage of total indirect emissions. Estimated direct and indirect N_2O emissions by sub-source category are shown in Table 6-17 and Table 6-18.

Table 6-15: N_2O Emissions from Agricultural Soils (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Direct	**153.8**	**162.6**	**167.5**	**163.7**	**165.1**	**166.6**	**160.2**
Cropland	102.9	115.6	118.1	115.6	117.8	117.9	112.0
Grassland	50.9	47.1	49.4	48.1	47.3	48.7	48.2
Indirect (All Land-Use Types)	**44.0**	**44.1**	**43.9**	**45.2**	**44.3**	**44.1**	**44.4**

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[145] Nitrification and denitrification are driven by the activity of microorganisms in soils. Nitrification is the aerobic microbial oxidation of ammonium (NH_4^+) to nitrate (NO_3^-), and denitrification is the anaerobic microbial reduction of nitrate to N_2. Nitrous oxide is a gaseous intermediate product in the reaction sequence of denitrification, which leaks from microbial cells into the soil and then into the atmosphere. Nitrous oxide is also produced during nitrification, although by a less well-understood mechanism (Nevison 2000).

[146] Drainage and cultivation of organic soils in former wetlands enhances mineralization of N-rich organic matter, thereby increasing N_2O emissions from these soils.

[147] Asymbiotic N fixation is the fixation of atmospheric N_2 by bacteria living in soils that do not have a direct relationship with plants.

[148] These processes entail volatilization of applied or mineralized N as NH_3 and NO_x, transformation of these gases within the atmosphere (or upon deposition), and deposition of the N primarily in the form of particulate NH_4^+, nitric acid (HNO_3), and NO_x.

Cropland	37.5	37.7	36.8	38.6	37.6	37.5	37.5
Grassland	6.1	5.8	6.3	5.9	5.9	5.9	6.2
Forest Land	+	0.1	0.1	0.1	0.1	0.1	0.1
Settlements	0.3	0.4	0.6	0.6	0.6	0.6	0.6
Total	**197.8**	**206.8**	**211.3**	**208.9**	**209.4**	**210.7**	**204.6**

+ Less than 0.05 Tg CO_2 Eq.

Table 6-16: N_2O Emissions from Agricultural Soils (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Direct	**496**	**525**	**540**	**528**	**533**	**538**	**517**
Cropland	332	373	381	373	380	380	361
Grassland	164	152	159	155	152	157	155
Indirect (All Land-Use Types)	**142**	**142**	**142**	**146**	**143**	**142**	**143**
Cropland	121	122	119	125	121	121	121
Grassland	20	19	20	19	19	19	20
Forest Land	0	+	+	+	+	+	+
Settlements	1	1	2	2	2	2	2
Total	**638**	**667**	**682**	**674**	**675**	**680**	**660**

+ Less than 0.5 Gg N_2O

Table 6-17: Direct N_2O Emissions from Agricultural Soils by Land Use Type and N Input Type (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Cropland	**102.9**	**115.6**	**118.1**	**115.6**	**117.8**	**117.9**	**112.0**
Mineral Soils	100.1	112.7	115.2	112.7	114.9	115.0	109.1
Mineralization and Asymbiotic Fixation	*44.6*	*50.6*	*50.5*	*49.7*	*50.9*	*50.9*	*47.1*
Synthetic Fertilizer	*32.3*	*36.0*	*38.6*	*36.7*	*37.4*	*37.3*	*36.9*
Residue N[a]	*12.4*	*14.3*	*13.7*	*13.8*	*13.9*	*14.3*	*13.1*
Organic Amendments[b]	*10.8*	*11.8*	*12.3*	*12.5*	*12.8*	*12.5*	*12.1*
Organic Soils	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Grassland	**50.9**	**47.1**	**49.4**	**48.1**	**47.3**	**48.7**	**48.2**
Residue N[c]	15.6	13.8	14.6	14.2	13.9	14.4	14.1
PRP Manure	8.1	7.9	8.2	8.1	8.0	8.2	7.9
Synthetic Fertilizer	3.9	3.9	4.1	4.0	3.9	4.0	3.9
Managed Manure[d]	1.5	1.6	1.6	1.6	1.6	1.6	1.6
Sewage Sludge	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Mineralization and Asymbiotic Fixation	21.5	19.5	20.4	19.7	19.3	20.0	20.1
Total	**153.8**	**162.6**	**167.5**	**163.7**	**165.1**	**166.6**	**160.2**

[a] Cropland residue N inputs include N in unharvested legumes as well as crop residue N.

[b] Organic amendment inputs include managed manure amendments, daily spread manure amendments, and commercial organic fertilizers (i.e., dried blood, dried manure, tankage, compost, and other).

[c] Grassland residue N inputs include N in ungrazed legumes as well as ungrazed grass residue N

[d] Accounts for managed manure and daily spread manure amendments that are applied to grassland soils.

Table 6-18: Indirect N_2O Emissions from all Land-Use Types (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Cropland	**37.5**	**37.7**	**36.8**	**38.6**	**37.6**	**37.5**	**37.5**
Volatilization & Atm. Deposition	11.6	12.7	13.1	14.2	12.8	12.9	13.4
Surface Leaching & Run-Off	25.8	25.0	23.7	24.4	24.9	24.5	24.1
Grassland	**6.1**	**5.8**	**6.3**	**5.9**	**5.9**	**5.9**	**6.2**
Volatilization & Atm. Deposition	5.1	4.7	4.8	4.8	4.7	4.7	4.7

Surface Leaching & Run-Off	1.0		1.2		1.5	1.1	1.2	1.2	1.5
Forest Land	**+**		**0.1**		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Volatilization & Atm. Deposition	+		+		+	+	+	+	+
Surface Leaching & Run-Off	+		0.1		0.1	0.1	0.1	0.1	0.1
Settlements	**0.3**		**0.4**		**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Volatilization & Atm. Deposition	0.1		0.1		0.2	0.2	0.2	0.2	0.2
Surface Leaching & Run-Off	0.2		0.3		0.4	0.4	0.4	0.4	0.4
Total	**44.0**		**44.1**		**43.9**	**45.2**	**44.3**	**44.1**	**44.4**

+ Less than 0.05 Tg CO_2 Eq.

Figure 6-3 through Figure 6-6 show regional patterns in direct N_2O emissions, and also show N losses from volatilization, leaching, and runoff that lead to indirect N_2O emissions. Average annual emissions and N losses are shown for croplands that produce major crops and from grasslands in each state. Direct N_2O emissions from croplands tend to be high in the Corn Belt (Illinois, Iowa, Indiana, Ohio, southern Minnesota, southern Wisconsin, and eastern Nebraska), where a large portion of the land is used for growing highly fertilized corn and N-fixing soybean crops. Direct emissions are also high in Missouri, Kansas, and Texas, primarily from irrigated cropping in western Texas, dryland wheat in Kansas, and hay cropping in eastern Texas and Missouri. Direct emissions are low in many parts of the eastern United States because a small portion of land is cultivated, and also low in many western states where rainfall and access to irrigation water are limited.

Direct emissions (Tg CO_2 Eq./state/year) from grasslands are highest in the central and western United States (Figure 6-4) where a high proportion of the land is used for cattle grazing. Some areas in the Great Lake states, the Northeast, and Southeast have moderate to low emissions even though emissions from these areas tend to be high on a per unit area basis, because the total amount of grassland is much lower than in the central and western United States.

Indirect emissions from croplands and grasslands (Figure 6-5 and Figure 6-6) show patterns similar to direct emissions, because the factors that control direct emissions (N inputs, weather, soil type) also influence indirect emissions. However, there are some exceptions, because the processes that contribute to indirect emissions (NO_3^- leaching, N volatilization) do not respond in exactly the same manner as the processes that control direct emissions (nitrification and denitrification). For example, coarser-textured soils facilitate relatively high indirect emissions in Florida grasslands due to high rates of N volatilization and NO_3^- leaching, even though they have only moderate rates of direct N_2O emissions.

Figure 6-3: Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)
[Figure will be provided in public review]

Figure 6-4: Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)
[Figure will be provided in public review]

Figure 6-5: Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)
[Figure will be provided in public review]

Figure 6-6: Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)
[Figure will be provided in public review]

Methodology

The *2006 IPCC Guidelines* (IPCC 2006) divide the Agricultural Soil Management source category into four components: (1) direct emissions due to N additions to cropland and grassland mineral soils, including synthetic fertilizers, sewage sludge applications, crop residues, organic amendments, and biological N fixation associated with planting of legumes on cropland and grassland soils; (2) direct emissions from drainage and cultivation of organic cropland soils; (3) direct emissions from soils due to the deposition of manure by livestock on PRP grasslands; and (4) indirect emissions from soils and water due to N additions and manure deposition to soils that lead to volatilization, leaching, or runoff of N and subsequent conversion to N_2O.

The United States has adopted recommendations from IPCC (2006) on methods for agricultural soil management. These recommendations include (1) estimating the contribution of N from crop residues to indirect soil N_2O emissions; (2) adopting a revised emission factor for direct N_2O emissions to the extent that Tier 1 methods are used in the Inventory (described later in this section); (3) removing double counting of emissions from N-fixing crops associated with the biological N fixation and crop residue N input categories; (4) using revised crop residue statistics to compute N inputs to soils based on harvest yield data to the extent that Tier 1 methods are used in the Inventory; (5) accounting for indirect as well as direct emissions from N made available via mineralization of soil organic matter and litter, in addition to asymbiotic fixation[149] (i.e., computing total emissions from managed land); and (6) reporting all emissions from managed lands, largely because management affects all processes leading to soil N_2O emissions. One recommendation from IPCC (2006) that has not been adopted is the accounting of emissions from pasture renewal, which involves occasional plowing to improve forage production. This practice is not common in the United States, and is not estimated.

The methodology used to estimate emissions from agricultural soil management in the United States is based on a combination of IPCC Tier 1 and 3 approaches. A Tier 3, process-based model (DAYCENT) was used to estimate direct emissions from major crops on mineral (i.e., non-organic) soils; as well as most of the direct emissions from grasslands. The Tier 3 approach has been specifically designed and tested to estimate N_2O emissions in the United States, accounting for more of the environmental and management influences on soil N_2O emissions than the IPCC Tier 1 method (see Box 6-1 for further elaboration). The Tier 1 IPCC (2006) methodology was used to estimate (1) direct emissions from non-major crops on mineral soils (e.g., barley, oats, vegetables, and other crops); (2) the portion of the grassland direct emissions that were not estimated with the Tier 3 DAYCENT model (i.e., federal grasslands); and (3) direct emissions from drainage and cultivation of organic cropland soils. Indirect emissions were also estimated with a combination of DAYCENT and the IPCC Tier 1 method.

In past Inventories, attempts were made to subtract "background" emissions that would presumably occur if the lands were not managed. However, this approach is likely to be inaccurate for estimating the anthropogenic influence on soil N_2O emissions. Moreover, if background emissions could be measured or modeled based on processes unaffected by anthropogenic activity, they would be a very small portion of the total emissions, due to the high inputs of N to agricultural soils from fertilization and legume cropping. Given the recommendation from IPCC (2006) and the influence of management on all processes leading to N_2O emissions from soils in agricultural systems, the decision was made to report total emissions from managed lands for this source category. Annex 3.11 provides more detailed information on the methodologies and data used to calculate N_2O emissions from each component.

[BEGIN BOX]

Box 6-1. Tier 1 vs. Tier 3 Approach for Estimating N_2O Emissions

The IPCC (2006) Tier 1 approach is based on multiplying activity data on different N inputs (e.g., synthetic fertilizer, manure, N fixation, etc.) by the appropriate default IPCC emission factors to estimate N_2O emissions on an input-by-input basis. The Tier 1 approach requires a minimal amount of activity data, readily available in most countries (e.g., total N applied to crops); calculations are simple; and the methodology is highly transparent. In contrast, the Tier 3 approach developed for this Inventory employs a process-based model (i.e., DAYCENT) that represents the interaction of N inputs and the environmental conditions at specific locations. Consequently, the Tier

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[149] N inputs from asymbiotic N fixation are not directly addressed in *2006 IPCC Guidelines*, but are a component of the total emissions from managed lands and are included in the Tier 3 approach developed for this source.

3 approach is likely to produce more accurate estimates; it accounts more comprehensively for land-use and management impacts and their interaction with environmental factors (i.e., weather patterns and soil characteristics), which will enhance or dampen anthropogenic influences. However, the Tier 3 approach requires more detailed activity data (e.g., crop-specific N amendment rates), additional data inputs (e.g., daily weather, soil types, etc.), and considerable computational resources and programming expertise. The Tier 3 methodology is less transparent, and thus it is critical to evaluate the output of Tier 3 methods against measured data in order to demonstrate the adequacy of the method for estimating emissions (IPCC 2006). Another important difference between the Tier 1 and Tier 3 approaches relates to assumptions regarding N cycling. Tier 1 assumes that N added to a system is subject to N_2O emissions only during that year and cannot be stored in soils and contribute to N_2O emissions in subsequent years. This is a simplifying assumption that is likely to create bias in estimated N_2O emissions for a specific year. In contrast, the process-based model used in the Tier 3 approach includes such legacy effects when N added to soils is re-mineralized from soil organic matter and emitted as N_2O during subsequent years.

[END BOX]

Direct N_2O Emissions from Cropland Soils

Major Crop Types on Mineral Cropland Soils

The DAYCENT ecosystem model (Del Grosso et al. 2001, Parton et al. 1998) was used to estimate direct N_2O emissions from mineral cropland soils that are managed for production of major crops—specifically corn, soybeans, wheat, alfalfa hay, other hay, sorghum, and cotton—representing approximately 90 percent of total croplands in the United States. For these croplands, DAYCENT was used to simulate crop growth, soil organic matter decomposition, greenhouse gas fluxes, and key biogeochemical processes affecting N_2O emissions, and the simulations were driven by model input data generated from daily weather records (Thornton et al. 1997, 2000; Thornton and Running 1999), land management surveys (see citations below), and soil physical properties determined from national soil surveys (Soil Survey Staff 2005). Note that the influence of land-use change on soil N_2O emissions was not addressed in this analysis, but is a planned improvement.

DAYCENT simulations were conducted for each major crop at the county scale in the United States. Simulating N_2O emissions at the county scale was facilitated by soil and weather data that were available for every county with more than 100 acres of agricultural land, and by land management data (e.g., timing of planting, harvesting, and intensity of cultivation) that were available at the agricultural-region level as defined by the Agricultural Sector Model (McCarl et al. 1993). ASM has 63 agricultural regions in the contiguous United States. Most regions correspond to one state, except for those states with greater heterogeneity in agricultural practices; in such cases, more than one region is assigned to a state. While cropping systems were simulated for each county, the results best represent emissions at regional (i.e., state) and national levels due to the regional scale of management data, which include model parameters that determined the influence of management activities on soil N_2O emissions (e.g., when crops were planted/harvested).

Nitrous oxide emissions from managed agricultural lands are the result of interactions among anthropogenic activities (e.g., N fertilization, manure application, tillage) and other driving variables, such as weather and soil characteristics. These factors influence key processes associated with N dynamics in the soil profile, including immobilization of N by soil microbial organisms, decomposition of organic matter, plant uptake, leaching, runoff, and volatilization, as well as the processes leading to N_2O production (nitrification and denitrification). It is not possible to partition N_2O emissions into each anthropogenic activity directly from model outputs due to the complexity of the interactions (e.g., N_2O emissions from synthetic fertilizer applications cannot be distinguished from those resulting from manure applications). To approximate emissions by activity, the amount of mineral N added to the soil for each of these sources was determined and then divided by the total amount of mineral N that was made available in the soil according to the DAYCENT model. The percentages were then multiplied by the total of direct N_2O emissions in order to approximate the portion attributed to key practices. This approach is only an approximation because it assumes that all N made available in soil has an equal probability of being released as N_2O, regardless of its source, which is unlikely to be the case (Delgado et al., 2009). However, this approach allows for further disaggregation of emissions by source of N, which is valuable for reporting purposes and is analogous to the reporting associated with the IPCC (2006) Tier 1 method, in that it associates portions of the total soil N_2O

emissions with individual sources of N.

DAYCENT was used to estimate direct N_2O emissions due to mineral N available from: (1) the application of synthetic fertilizers; (2) the application of livestock manure; (3) the retention of crop residues (i.e., leaving residues in the field after harvest instead of burning or collecting residues); and (4) mineralization of soil organic matter and litter, in addition to asymbiotic fixation. Note that commercial organic fertilizers are addressed with the Tier 1 method because county-level application data would be needed to simulate applications in DAYCENT, and currently data are only available at the national scale. The third and fourth sources are generated internally by the DAYCENT model. For the first two practices, annual changes in soil mineral N due to anthropogenic activity were obtained or derived from the following sources:

- Crop-specific N-fertilization rates: Data sources for fertilization rates include Alexander and Smith (1990), Anonymous (1924), Battaglin and Goolsby (1994), Engle and Makela (1947), ERS (1994, 2003), Fraps and Asbury (1931), Ibach and Adams (1967), Ibach et al. (1964), NFA (1946), NRIAI (2003), Ross and Mehring (1938), Skinner (1931), Smalley et al. (1939), Taylor (1994), and USDA (1966, 1957, 1954, 1946). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA *Economic Research Service Cropping Practices Survey* (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004).
- Managed manure production and application to croplands and grasslands: Manure N amendments and daily spread manure N amendments applied to croplands and grasslands (not including PRP manure) were determined using USDA Manure N Management Databases for 1997 (Kellogg et al. 2000; Edmonds et al. 2003). Amendment data for 1997 were scaled to estimate values for other years based on the availability of managed manure N for application to soils in 1997 relative to other years. The amount of available N from managed manure for each livestock type was calculated as described in the Manure Management section (Section 6.2) and Annex 3.10.
- Retention of crop residue, N mineralization from soil organic matter, and asymbiotic N fixation from the atmosphere: The IPCC approach considers crop residue N and N mineralized from soil organic matter as activity data. However, they are not treated as activity data in DAYCENT simulations because residue production, N fixation, mineralization of N from soil organic matter, and asymbiotic fixation are internally generated by the model as part of the simulation. In other words, DAYCENT accounts for the influence of N fixation, mineralization of N from soil organic matter, and retention of crop residue on N_2O emissions, but these are not model inputs. The DAYCENT simulations also accounted for the approximately 3 percent of grain crop residues that were assumed to be burned based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996), and therefore did not contribute to soil N_2O emissions.
- Historical and modern crop rotation and management information (e.g., timing and type of cultivation, timing of planting/harvest, etc.): These activity data were derived from Hurd (1930, 1929), Latta (1938), Iowa State College Staff Members (1946), Bogue (1963), Hurt (1994), USDA (2000a) as extracted by Eve (2001) and revised by Ogle (2002), CTIC (1998), Piper et al. (1924), Hardies and Hume (1927), Holmes (1902, 1929), Spillman (1902, 1905, 1907, 1908), Chilcott (1910), Smith (1911), Kezer (ca. 1917), Hargreaves (1993), ERS (2002), Warren (1911), Langston et al. (1922), Russell et al. (1922), Elliott and Tapp (1928), Elliott (1933), Ellsworth (1929), Garey (1929), Hodges et al. (1930), Bonnen and Elliott (1931), Brenner et al. (2002, 2001), and Smith et al. (2002).

DAYCENT simulations produced per-area estimates of N_2O emissions ($g\ N_2O\text{-}N/m^2$) for major crops in each county, which were multiplied by the cropland areas in each county to obtain county-scale emission estimates. Cropland area data were from NASS (USDA 2010a, 2010b). The emission estimates by reported crop areas in the county were scaled to the regions (and states for mapping purposes when there was more than one region in a state), and the national estimate was calculated by summing results across all regions. DAYCENT is sensitive to interannual variability in weather patterns and other controlling variables, so emissions associated with individual activities vary through time even if the management practices remain the same (e.g., if N fertilization remains the same for two years). In contrast, Tier 1 methods do not capture this variability and rather have a linear, monotonic response that depends solely on management practices. DAYCENT's ability to capture these interactions between management and environmental conditions produces more accurate estimates of N_2O emissions than the Tier 1 method.

Non-Major Crop Types on Mineral Cropland Soils

The IPCC (2006) Tier 1 methodology was used to estimate direct N_2O emissions for mineral cropland soils that are managed for production of non-major crop types, including barley, oats, tobacco, sugarcane, sugar beets, sunflowers, millet, rice, peanuts, and other crops that were not included in the DAYCENT simulations. Estimates of direct N_2O emissions from N applications to non-major crop types were based on mineral soil N that was made available from the following practices: (1) the application of synthetic commercial fertilizers; (2) application of managed manure and non-manure commercial organic fertilizers;[150] and (3) the retention of above- and below-ground crop residues in agricultural fields (i.e., crop biomass that is not harvested). Non-manure organic amendments were not included in the DAYCENT simulations because county-level data were not available. Consequently, non-manure organic amendments, as well as additional manure that was not added to major crops in the DAYCENT simulations, were included in the Tier 1 analysis. The influence of land-use change on soil N_2O emissions from non-major crops has not been addressed in this analysis, but is a planned improvement. The following sources were used to derive activity data:

- A process-of-elimination approach was used to estimate synthetic N fertilizer additions for non-major crops, because little information exists on their fertilizer application rates. The total amount of fertilizer used on farms has been estimated by the USGS from sales records (Ruddy et al. 2006), and these data were aggregated to obtain state-level N additions to farms. After subtracting the portion of fertilizer applied to major crops and grasslands (see sections on Major Crops and Grasslands for information on data sources), the remainder of the total fertilizer used on farms was assumed to be applied to non-major crops.
- A process-of-elimination approach was used to estimate manure N additions for non-major crops, because little information exists on application rates for these crops. The amount of manure N applied to major crops and grasslands was subtracted from total manure N available for land application (see sections on Major Crops and Grasslands for information on data sources), and this difference was assumed to be applied to non-major crops.
- Non-manure, non-sewage-sludge commercial organic fertilizer additions were based on organic fertilizer consumption statistics, which were converted to units of N using average organic fertilizer N content (TVA 1991 through 1994; AAPFCO 1995 through 2010). Manure and sewage sludge components were subtracted from total commercial organic fertilizers to avoid double counting.
- Crop residue N was derived by combining amounts of above- and below-ground biomass, which were determined based on crop production yield statistics (USDA 1994, 1998, 2003, 2005, 2006, 2008, 2009, 2010a), dry matter fractions (IPCC 2006), linear equations to estimate above-ground biomass given dry matter crop yields from harvest (IPCC 2006), ratios of below-to-above-ground biomass (IPCC 2006), and N contents of the residues (IPCC 2006). Approximately 3 percent of the crop residues were burned and therefore did not contribute to soil N_2O emissions, based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996).

The total increase in soil mineral N from applied fertilizers and crop residues was multiplied by the IPCC (2006) default emission factor to derive an estimate of direct N_2O emissions from non-major crop types.

Drainage and Cultivation of Organic Cropland Soils

The IPCC (2006) Tier 1 methods were used to estimate direct N_2O emissions due to drainage and cultivation of organic soils at a state scale. State-scale estimates of the total area of drained and cultivated organic soils were obtained from the *National Resources Inventory* (NRI) (USDA 2000a, as extracted by Eve 2001 and amended by Ogle 2002). Temperature data from Daly et al. (1994, 1998) were used to subdivide areas into temperate and sub-tropical climates using the climate classification from IPCC (2006). Data were available for 1982, 1992 and 1997. To estimate annual emissions, the total temperate area was multiplied by the IPCC default emission factor for temperate regions, and the total sub-tropical area was multiplied by the average of the IPCC default emission factors for temperate and tropical regions (IPCC 2006).

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[150] Commercial organic fertilizers include dried blood, tankage, compost, and other; dried manure and sewage sludge that are used as commercial fertilizer have been excluded to avoid double counting. The dried manure N is counted with the non-commercial manure applications, and sewage sludge is assumed to be applied only to grasslands.

Direct N_2O Emissions from Grassland Soils

As with N_2O from croplands, the Tier 3 process-based DAYCENT model and Tier 1 method described in IPCC (2006) were combined to estimate emissions from grasslands. Grasslands include pastures and rangelands used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grasslands that are not intensively managed, while pastures are often seeded grasslands, possibly following tree removal, which may or may not be improved with practices such as irrigation and interseeding legumes.

DAYCENT was used to simulate county-scale N_2O emissions from non-federal grasslands resulting from manure deposited by livestock directly onto pastures and rangelands (i.e., PRP manure), N fixation from legume seeding, managed manure amendments (i.e., manure other than PRP manure), and synthetic fertilizer application. Other N inputs were simulated within the DAYCENT framework, including N input from mineralization due to decomposition of soil organic matter and N inputs from senesced grass litter, as well as asymbiotic fixation of N from the atmosphere. The simulations used the same weather, soil, and synthetic N fertilizer data as discussed under the section for Major Crop Types on Mineral Cropland Soils. Managed manure N amendments to grasslands were estimated from Edmonds et al. (2003) and adjusted for annual variation using data on the availability of managed manure N for application to soils, according to methods described in the Manure Management section (Section 6.2) and Annex 3.10. Biological N fixation is simulated within DAYCENT and therefore was not an input to the model.

Manure N deposition from grazing animals (i.e., PRP manure) is another key input of N to grasslands. The amounts of PRP manure N applied on non-federal and federal grasslands in each county were based on the proportion of non-federal to federal grassland area (See below for more information on area data). The amount of PRP manure applied on non-federal grasslands was an input to the DAYCENT model (see Annex 3.10), and included approximately 91 percent of total PRP manure. The remainder of the PRP manure N excretions in each county was assumed to be excreted on federal grasslands (i.e., DAYCENT simulations were only conducted for non-federal grasslands), and the N_2O emissions were estimated using the IPCC (2006) Tier 1 method with IPCC default emission factors. Sewage sludge was assumed to be applied on grasslands because of the heavy metal content and other pollutants in human waste that limit its use as an amendment to croplands. Sewage sludge application was estimated from data compiled by EPA (1993, 1999, 2003), McFarland (2001), and NEBRA (2007). Sewage sludge data on soil amendments to agricultural lands were only available at the national scale, and it was not possible to associate application with specific soil conditions and weather at the county scale. Therefore, DAYCENT could not be used to simulate the influence of sewage sludge amendments on N_2O emissions from grassland soils, and consequently, emissions from sewage sludge were estimated using the IPCC (2006) Tier 1 method.

Grassland area data were consistent with the Land Representation reported in Section 7.1. Data were obtained from the U.S. Department of Agriculture *National Resources Inventory* (USDA 2000a, Nusser and Goebel 1997, http://www.ncgc.nrcs.usda.gov/products/nri/index.htm) and the U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD, Vogelman et al. 2001, http://www.mrlc.gov), which were reconciled with the Forest Inventory and Analysis Data (http://fia.fs.us/tools-data/data). The area data for pastures and rangeland were aggregated to the county level to estimate non-federal and federal grassland areas.

DAYCENT simulations produced per-area estimates of N_2O emissions (g N_2O-N/m^2) for pasture and rangelands, which were multiplied by the non-federal grassland areas in each county. The county-scale N_2O emission estimates for non-federal grasslands were scaled to the 63 agricultural regions (and to the state level for mapping purposes if there was more than one region in a state), and the national estimate was calculated by summing results across all regions. Tier 1 estimates of N_2O emissions for the PRP manure N deposited on federal grasslands and applied sewage sludge N were produced by multiplying the N input by the appropriate emission factor. Tier 1 estimates for emissions from manure N were calculated at the state level and aggregated to the entire country but emission from sewage sludge N were calculated exclusively at the national scale.

Total Direct N_2O Emissions from Cropland and Grassland Soils

Annual direct emissions from major and non-major crops on mineral cropland soils, from drainage and cultivation of organic cropland soils, and from grassland soils were summed to obtain the total direct N_2O emissions from agricultural soil management (see Table 6-15 and Table 6-16).

Indirect N_2O Emissions from Managed Soils of all Land-Use Types

This section describes the methods used for estimating indirect soil N_2O emissions from all land-use types (i.e., croplands, grasslands, forest lands, and settlements). Indirect N_2O emissions occur when mineral N made available through anthropogenic activity is transported from the soil either in gaseous or aqueous forms and later converted into N_2O. There are two pathways leading to indirect emissions. The first pathway results from volatilization of N as NO_x and NH_3 following application of synthetic fertilizer, organic amendments (e.g., manure, sewage sludge), and deposition of PRP manure. N made available from mineralization of soil organic matter and asymbiotic fixation also contributes to volatilized N emissions. Volatilized N can be returned to soils through atmospheric deposition, and a portion of the deposited N is emitted to the atmosphere as N_2O. The second pathway occurs via leaching and runoff of soil N (primarily in the form of NO_3^-) that was made available through anthropogenic activity on managed lands, mineralization of soil organic matter, and asymbiotic fixation. The NO_3^- is subject to denitrification in water bodies, which leads to N_2O emissions. Regardless of the eventual location of the indirect N_2O emissions, the emissions are assigned to the original source of the N for reporting purposes, which here includes croplands, grasslands, forest lands, and settlements.

Indirect N_2O Emissions from Atmospheric Deposition of Volatilized N from Managed Soils

As in the direct emissions calculation, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 methods were combined to estimate the amount of N that was volatilized and eventually emitted as N_2O. DAYCENT was used to estimate N volatilization for land areas whose direct emissions were simulated with DAYCENT (i.e., major croplands and most grasslands). The N inputs included are the same as described for direct N_2O emissions in the sections on major crops and grasslands. Nitrogen volatilization for all other areas was estimated using the Tier 1 method and default IPCC fractions for N subject to volatilization (i.e., N inputs on non-major croplands, PRP manure N excretion on federal grasslands, sewage sludge application on grasslands). The Tier 1 method and default fractions were also used to estimate N subject to volatilization from N inputs on settlements and forest lands (see the Land Use, Land-Use Change, and Forestry chapter). For the volatilization data generated from both the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N_2O emissions occurring due to re-deposition of the volatilized N (Table 6-18).

Indirect N_2O Emissions from Leaching/Runoff

As with the calculations of indirect emissions from volatilized N, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 method were combined to estimate the amount of N that was subject to leaching and surface runoff into water bodies, and eventually emitted as N_2O. DAYCENT was used to simulate the amount of N transported from lands used to produce major crops and most grasslands. N transport from all other areas was estimated using the Tier 1 method and the IPCC (2006) default factor for the proportion of N subject to leaching and runoff. This N transport estimate includes N applications on croplands that produce non-major crops, sewage sludge amendments on grasslands, PRP manure N excreted on federal grasslands, and N inputs on settlements and forest lands. For both the DAYCENT and IPCC (2006) Tier 1 methods, nitrate leaching was assumed to be an insignificant source of indirect N_2O in cropland and grassland systems in arid regions as discussed in IPCC (2006). In the United States, the threshold for significant nitrate leaching is based on the potential evapotranspiration (PET) and rainfall amount, similar to IPCC (2006), and is assumed to be negligible in regions where the amount of precipitation plus irrigation does not exceed 80 percent of PET. For leaching and runoff data estimated by the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N_2O emissions that occur in groundwater and waterways (Table 6-18).

Uncertainty and Time-Series Consistency

Uncertainty was estimated for each of the following five components of N_2O emissions from agricultural soil management: (1) direct emissions calculated by DAYCENT; (2) the components of indirect emissions (N volatilized and leached or runoff) calculated by DAYCENT; (3) direct emissions calculated with the IPCC (2006) Tier 1 method; (4) the components of indirect emissions (N volatilized and leached or runoff) calculated with the IPCC (2006) Tier 1 method; and (5) indirect emissions calculated with the IPCC (2006) Tier 1 method. Uncertainty in direct emissions, which account for the majority of N_2O emissions from agricultural management, as well as the components of indirect emissions calculated by DAYCENT were estimated with a Monte Carlo Analysis, addressing uncertainties in model inputs and structure (i.e., algorithms and parameterization) (Del Grosso et al., 2010). Uncertainties in direct emissions calculated with the IPCC (2006) Tier 1 method, the proportion of volatilization and leaching or runoff estimated with the IPCC (2006) Tier 1 method, and indirect N_2O emissions were estimated with a simple error propagation approach (IPCC 2006). Additional details on the uncertainty methods are provided in Annex 3.11.

Uncertainties from the Tier 1 and Tier 3 (i.e., DAYCENT) estimates were combined using simple error propagation (IPCC 2006), and the results are summarized in Table 6-19. Agricultural direct soil N_2O emissions in 2009 were estimated to be between 118.3 and 250.6 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 26 percent below and 56 percent above the 2009 emission estimate of 160.2 Tg CO_2 Eq. The indirect soil N_2O emissions in 2009 were estimated to range from 22.4 to 111.6 Tg CO_2 Eq. at a 95 percent confidence level, indicating an uncertainty of 50 percent below and 151 percent above the 2009 emission estimate of 44.4 Tg CO_2 Eq.

Table 6-19: Quantitative Uncertainty Estimates of N_2O Emissions from Agricultural Soil Management in 2009 (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Direct Soil N_2O Emissions	N_2O	160.2	118.3	250.6	-26%	+56%
Indirect Soil N_2O Emissions	N_2O	44.4	22.4	111.6	-50%	+151%

Note: Due to lack of data, uncertainties in areas for major crops, managed manure N production, PRP manure N production, other organic fertilizer amendments, indirect losses of N in the DAYCENT simulations, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

For quality control, DAYCENT results for N_2O emissions and NO_3^- leaching were compared with field data representing various cropland and grassland systems, soil types, and climate patterns (Del Grosso et al. 2005, Del Grosso et al. 2008), and further evaluated by comparing to emission estimates produced using the IPCC (2006) Tier 1 method for the same sites. Nitrous oxide measurement data were available for 11 sites in the United States and one in Canada, representing 30 different combinations of fertilizer treatments and cultivation practices. DAYCENT estimates of N_2O emissions were closer to measured values at all sites compared to the IPCC Tier 1 estimate, except for Colorado dryland cropping (Figure 6-7). In general, IPCC Tier 1 methodology tends to over-estimate emissions when observed values are low and under-estimate emissions when observed values are high, while DAYCENT estimates are less biased. This is not surprising because DAYCENT accounts for site-level factors (weather, soil type) that influence N_2O emissions. Nitrate leaching data were available for three sites in the United States representing nine different combinations of fertilizer amendments. Linear regressions of simulated vs. observed emission and leaching data yielded correlation coefficients of 0.89 and 0.94 for annual N_2O emissions and NO_3^- leaching, respectively. This comparison demonstrates that DAYCENT provides relatively high predictive capability for N_2O emissions and NO_3^- leaching, and is an improvement over the IPCC Tier 1 method (see additional information in Annex 3.11).

Figure 6-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model

Spreadsheets containing input data and probability distribution functions required for DAYCENT simulations of major croplands and grasslands and unit conversion factors were checked, as were the program scripts that were used to run the Monte Carlo uncertainty analysis. Several errors were identified following re-organization of the calculation spreadsheets, and corrective actions have been taken. In particular, some of the links between spreadsheets were missing or needed to be modified. Spreadsheets containing input data, emission factors, and calculations required for the Tier 1 approach were checked and no errors were found.

Recalculations Discussion

Two major revisions were made in the Agricultural Soil Management section for the current Inventory.

First, the methodology used to estimate grassland areas was updated and revised to be consistent with the Land Representation used in the Land Use, Land Use Change and Forestry sector (see Section 7.1). This led to an overall decrease in grassland area, and lower emissions than reported in the prior Inventory. Second, the methodology used to calculate livestock manure N was changed such that total manure N added to soils increased by approximately 11 percent (see Section 6.2 for details).

The recalculations had opposite impacts on the emissions, with less grassland area tending to decrease emissions and higher manure N inputs tending to increase emissions. In some years emissions were higher overall, but on average, these changes led to a lower amount of N_2O emissions from agricultural soil management by about 1.5 percent over the time series relative to the previous Inventory.

Planned Improvements

A key improvement is underway for Agricultural Soil Management to incorporate more land-use survey data from the NRI (USDA 2000a) into the DAYCENT simulation analysis, beyond the area estimates for rangeland and pasture that are currently used to estimate emissions from grasslands. NRI has a record of land-use activities since 1979 for all U.S. agricultural land, which is estimated at about 386 Mha. NASS is used as the basis for land-use records in the current Inventory, and there are three major disadvantages to this dataset. First, most crops are grown in rotation with other crops (e.g., corn-soybean), but NASS data provide no information regarding rotation histories. In contrast, NRI is designed to track rotation histories, which is important because emissions from any particular year can be influenced by the crop that was grown the previous year. Second, NASS does not conduct a complete survey of cropland area each year, leading to gaps in the land base. NRI provides a complete history of cropland areas for four out of every five years from 1979 to 1997, and then every year after 1998. Third, the current inventory based on NASS does not quantify the influence of land-use change on emissions, which can be addressed using the NRI survey records. NRI also provides additional information on pasture land management that can be incorporated into the analysis (particularly the use of irrigation). Using NRI data will also make the Agricultural Soil Management methods more consistent with the methods used to estimate C stock changes for agricultural soils. The structure of model input files that contain land management data are currently being extensively revised to facilitate use of the annualized NRI data. This improvement is planned for completion by the next Inventory.

Another improvement is to reconcile the amount of crop residues burned with the Field Burning of Agricultural Residues source category (Section 6.5). This year the methodology for Field Burning of Agricultural Residues was significantly updated, but the changes were implemented too late for the new estimates of crop residues burned to be incorporated into the DAYCENT runs for the Agricultural Soil Management source. Next year the estimates will be reconciled; meanwhile the estimates presented in this section use the previous year's methodology for determining crop residues burned.

Other planned improvements are minor but will lead to more accurate estimates, including updating DAYMET weather data for more recent years following the release of new data, and using a rice-crop-specific emission factor for N amendments to rice areas.

6.5. Field Burning of Agricultural Residues (IPCC Source Category 4F)

Farming activities produce large quantities of agricultural crop residues, and farmers use or dispose of these residues in a variety of ways. For example, agricultural residues can be left on or plowed into the field; composted and then applied to soils; landfilled; or burned in the field. Alternatively, they can be collected and used as fuel, animal bedding material, supplemental animal feed, or construction material. Field burning of crop residues is not considered a net source of CO_2, because the C released to the atmosphere as CO_2 during burning is assumed to be reabsorbed during the next growing season. Crop residue burning is, however, a net source of CH_4, N_2O, CO, and NO_x, which are released during combustion.

Field burning is not a common method of agricultural residue disposal in the United States. The primary crop types whose residues are typically burned in the United States are corn, cotton, lentils, rice, soybeans, sugarcane, and wheat (McCarty 2009). In 2009, CH_4 and N_2O emissions from field burning were 0.2 Tg CO_2 Eq. (12 Gg) and 0.1 Tg. CO_2 Eq. (0.3 Gg), respectively. Annual emissions from this source over the period 1990 to 2009 have remained relatively constant, averaging approximately 0.2 Tg CO_2 Eq. (1 Gg) of CH_4 and 0.1 Tg CO_2 Eq. (0.3 Gg) of N_2O (see Table 6-20 and Table 6-21).

Table 6-20: CH_4 and N_2O Emissions from Field Burning of Agricultural Residues (Tg CO_2 Eq.)

Gas/Crop Type	1990	2000	2005	2006	2007	2008	2009
CH_4	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**	**0.3**	**0.2**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	0.1	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	0.1	0.1	+	0.1	+	+	+
Wheat	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
Total	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 6-21: CH_4, N_2O, CO, and NO_x Emissions from Field Burning of Agricultural Residues (Gg)

Gas/Crop Type	1990	2000	2005	2006	2007	2008	2009
CH_4	**13**	**12**	**9**	**11**	**11**	**13**	**12**
Corn	1	1	1	2	1	1	2
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	2	2	2	2	3	2	2
Soybeans	1	1	1	1	1	1	1
Sugarcane	3	2	1	3	1	2	2
Wheat	6	6	4	4	5	6	5
N_2O	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
CO	**268**	**259**	**184**	**233**	**237**	**270**	**247**
NO_x	**8**	**8**	**6**	**7**	**8**	**8**	**8**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

The Tier 2 methodology used for estimating greenhouse gas emissions from field burning of agricultural residues in the United States is consistent with IPCC (2006) (for more details, see Box 6-2). In order to estimate the amounts of C and N released during burning, the following equation was used:

C or N released = Σ over all crop types and states (Area Burned ÷ Crop Area Harvested × Crop Production ×

Residue/Crop Ratio × Dry Matter Fraction × Burning Efficiency × Combustion Efficiency × Fraction of C or N)

where,

Area Burned	= Total area of crop burned, by state
Crop Area Harvested	= Total area of crop harvested, by state
Crop Production	= Annual production of crop in Gg, by state
Residue/Crop Ratio	= Amount of residue produced per unit of crop production, by state
Dry Matter Fraction	= Amount of dry matter per unit of biomass for a crop
Fraction of C or N	= Amount of C or N per unit of dry matter for a crop
Burning Efficiency	= The proportion of prefire fuel biomass consumed[151]
Combustion Efficiency	= The proportion of C or N released with respect to the total amount of C or N available in the burned material, respectively[151]

Crop production and area harvested were available by state and year from USDA (2010) for all crops (except rice in Florida and Oklahoma, as detailed below). The amount C or N released was used in the following equation to determine the CH_4, CO, N_2O and NO_x emissions from the field burning of agricultural residues:

CH_4 and CO, or N_2O and NO_x Emissions from Field Burning of Agricultural Residues = (C or N Released) × (Emissions Ratio for C or N) × (Conversion Factor)

where,

Emissions Ratio	= g CH_4-C or CO-C/g C released, or g N_2O-N or NO_x-N/g N released
Conversion Factor	= conversion, by molecular weight ratio, of CH_4-C to C (16/12), or CO-C to C (28/12), or N_2O-N to N (44/28), or NO_x-N to N (30/14)

[BEGIN BOX]

Box 6-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach

This Inventory calculates emissions from Burning of Agricultural Residues using a Tier 2 methodology that is based on IPCC/UNEP/OECD/IEA (1997) and incorporates crop- and country-specific emission factors and variables. The equation used in this Inventory varies slightly in form from the one presented in the IPCC (2006) guidelines, but both equations rely on the same underlying variables. The IPCC (2006) equation was developed to be broadly applicable to all types of biomass burning, and, thus, is not specific to agricultural residues. IPCC (2006) default factors are provided only for four crops (wheat, corn, rice, and sugarcane), while this Inventory analyzes emissions from seven crops. A comparison of the methods and factors used in (1) the current Inventory and (2) the default IPCC (2006) approach was undertaken to determine the magnitude of the difference in overall estimates resulting from the two approaches. The IPCC (2006) approach was not used because crop-specific emission factors for N_2O were not available for all crops. In order to maintain consistency of methodology, the IPCC/UNEP/OECD/IEA (1997) approach presented in the Methodology section was used.

The IPCC (2006) default approach resulted in 12 percent higher emissions of CH_4 and 25 percent higher emissions of N_2O than the current estimates in this Inventory. It is reasonable to maintain the current methodology, since the IPCC (2006) defaults are only available for four crops and are worldwide average estimates, while current inventory estimates are based on U.S.-specific, crop-specific, published data.

[END BOX]

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[151] In IPCC/UNEP/OECD/IEA (1997), the equation for C or N released contains the variable ‘fraction oxidized in burning.’ This variable is equivalent to (burning efficiency × combustion efficiency).

Crop production data for all crops except rice in Florida and Oklahoma were taken from USDA's QuickStats service (USDA 2010). Rice production and area data for Florida and Oklahoma, which are not collected by USDA, were estimated separately. Average primary and ratoon crop yields for Florida (Schueneman and Deren 2002) were applied to Florida acreages (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010), and crop yields for Arkansas (USDA 2010) were applied to Oklahoma acreages[152] (Lee 2003 through 2006; Anderson 2008 through 2010). The production data for the crop types whose residues are burned are presented in Table 6-22. Crop weight by bushel was obtained from Murphy (1993).

The fraction of crop area burned was calculated using data on area burned by crop type and state[153] from McCarty (2010) for corn, cotton, lentils, rice, soybeans, sugarcane, and wheat.[154] McCarty (2010) used remote sensing data from Moderate Resolution Imaging Spectroradiometer (MODIS) to estimate area burned by crop. For the inventory analysis, the state-level area burned data were divided by state-level crop area harvested data to estimate the percent of crop area burned by crop and by state. The average fraction of area burned by crop across all states is shown in Table 6-23. All crop area harvested data were from USDA (2010), except for rice acreage in Florida and Oklahoma, which is not measured by USDA (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010; Lee 2003 through 2006; Anderson 2008 through 2010). Data on crop area burned were only available from McCarty (2010) for the years 2003 through 2007. For other years in the time series, the percent area burned was assumed to be equal to the average percent area burned from the 5 years for which data were available. This average was taken at the crop and state level. Table 6-23 shows these percent area estimates aggregated for the United States as a whole, at the crop level.

All residue/crop product mass ratios except sugarcane and cotton were obtained from Strehler and Stützle (1987). The datum for sugarcane is from Kinoshita (1988) and that of cotton from Huang et al. (2007). The residue/crop ratio for lentils was assumed to be equal to the average of the values for peas and beans. Residue dry matter fractions for all crops except soybeans, lentils, and cotton were obtained from Turn et al. (1997). Soybean and lentil dry matter fractions were obtained from Strehler and Stützle (1987); the value for lentil residue was assumed to equal the value for bean straw. The cotton dry matter fraction was taken from Huang et al. (2007). The residue C contents and N contents for all crops except soybeans and cotton are from Turn et al. (1997). The residue C content for soybeans is the IPCC default (IPCC/UNEP/OECD/IEA 1997). The N content of soybeans is from Barnard and Kristoferson (1985). The C and N contents of lentils were assumed to equal those of soybeans. The C and N contents of cotton are from Lachnicht et al. (2004). These data are listed in Table 6-24. The burning efficiency was assumed to be 93 percent, and the combustion efficiency was assumed to be 88 percent, for all crop types, except sugarcane (EPA 1994). For sugarcane, the burning efficiency was assumed to be 81 percent (Kinoshita 1988) and the combustion efficiency was assumed to be 68 percent (Turn et al. 1997). Emission ratios and conversion factors for all gases (see Table 6-25) were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 6-22: Agricultural Crop Production (Gg of Product)

Crop	1990	2000	2005	2006	2007	2008	2009
Corn[a]	201,534	251,854	282,263	267,503	331,177	307,142	333,011
Cotton	3,376	3,742	5,201	4,700	4,182	2,790	2,654
Lentils	40	137	238	147	166	109	266
Rice	7,114	8,705	10,132	8,843	9,033	9,272	9,972
Soybeans	52,416	75,055	83,507	87,001	72,859	80,749	91,417
Sugarcane	25,525	32,763	24,137	26,820	27,188	25,041	27,608
Wheat	74,292	60,641	57,243	49,217	55,821	68,016	60,366

[a] Corn for grain (i.e., excludes corn for silage).

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[152] Rice production yield data are not available for Oklahoma, so the Arkansas values are used as a proxy.

[153] Alaska and Hawaii were excluded.

[154] McCarty (2009) also examined emissions from burning of Kentucky bluegrass and a general "other crops/fallow" category, but USDA crop area and production data were insufficient to estimate emissions from these crops using the methodology employed in the Inventory. McCarty (2009) estimates that approximately 18 percent of crop residue emissions result from burning of the Kentucky bluegrass and "other" categories.

Table 6-23: U.S. Average Percent Crop Area Burned by Crop (Percent)

State	1990	2000	2005	2006	2007	2008	2009
Corn	+	+	+	+	+	+	+
Cotton	1	1	1	1	1	2	1
Lentils	3	2	+	2	1	1	1
Rice	10	10	6	8	12	9	9
Soybeans	+	+	+	+	+	+	+
Sugarcane	59	40	26	56	26	39	37
Wheat	3	3	2	3	3	3	3

+ Less than 0.5 percent

Table 6-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues

Crop	Residue/Crop Ratio	Dry Matter Fraction	C Fraction	N Fraction	Burning Efficiency (Fraction)	Combustion Efficiency (Fraction)
Corn	1.0	0.91	0.448	0.006	0.93	0.88
Cotton	1.6	0.90	0.445	0.012	0.93	0.88
Lentils	2.0	0.85	0.450	0.023	0.93	0.88
Rice	1.4	0.91	0.381	0.007	0.93	0.88
Soybeans	2.1	0.87	0.450	0.023	0.93	0.88
Sugarcane	0.2	0.62	0.424	0.004	0.81	0.68
Wheat	1.3	0.93	0.443	0.006	0.93	0.88

Table 6-25: Greenhouse Gas Emission Ratios and Conversion Factors

Gas	Emission Ratio	Conversion Factor
CH_4:C	0.005[a]	16/12
CO:C	0.060[a]	28/12
N_2O:N	0.007[b]	44/28
NO_x:N	0.121[b]	30/14

[a] Mass of C compound released (units of C) relative to mass of total C released from burning (units of C).

[b] Mass of N compound released (units of N) relative to mass of total N released from burning (units of N).

Uncertainty and Time-Series Consistency

Due to data and time limitations, uncertainty resulting from the fact that emissions from burning of Kentucky bluegrass and “other” residues are not included in the emissions estimates was not incorporated into the uncertainty analysis. The results of the Tier 2 Monte Carlo uncertainty analysis are summarized in Table 6-26. Methane emissions from field burning of agricultural residues in 2009 were estimated to be between 0.15 and 0.35 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 40 percent below and 42 percent above the 2009 emission estimate of 0.25 Tg CO_2 Eq. Also at the 95 percent confidence level, N_2O emissions were estimated to be between 0.07 and 0.14 Tg CO_2 Eq. (or approximately 30 percent below and 31 percent above the 2009 emission estimate of 0.10 Tg CO_2 Eq.).

Table 6-26: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Field Burning of Agricultural Residues (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Field Burning of Agricultural Residues	CH_4	0.25	0.15	0.35	-40%	+42%
Field Burning of Agricultural Residues	N_2O	0.10	0.07	0.14	-30%	+31%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for field burning of agricultural residues was implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and crops to attempt to identify any outliers or inconsistencies. For some crops and years in Florida and Oklahoma, the total area burned as measured by McCarty (2010) was greater than the area estimated for that crop, year, and state by USDA (2010), leading to a percent area burned estimate of greater than 100 percent. In such cases, it was assumed that the percent crop area burned for that state was 100 percent.

Recalculations Discussion

The methodology over the entire time series was revised relative to the previous Inventory to incorporate state- and crop-level data on area burned from McCarty (2010). (1) Cotton and lentils were added as crops; peanuts and barley were removed, because McCarty (2009) indicated that their residues are not burned in significant quantities in the United States; (2) fraction of residue burned was calculated at the state and crop level based on McCarty (2010) and USDA (2010) data, rather than a blanket application of 3 percent burned for all crops except rice and sugarcane, as was used in the previous Inventory; (3) since data from McCarty (2010) were only available for 5 years, the percent area burned for those 5 years was averaged by crop and state and used as an estimate for the remaining years in the time series. Because the percent area burned was lower than previously assumed for almost all crops, these recalculations have resulted in an average decrease in CH_4 emissions of 71 percent and an average decrease in N_2O emissions of 79 percent across the time series, relative to the previous Inventory.

Planned Improvements

Further investigation will be made into inconsistent data from Florida and Oklahoma as mentioned in the QA/QC and verification section, and attempts will be made to revise or further justify the assumption of 100 percent of area burned for those crops and years where the estimated percent area burned exceeded 100 percent. The availability of useable area harvested and other data for bluegrass and the “other crops” category in McCarty (2010) will also be investigated, in order to try to incorporate these emissions into the Inventory.

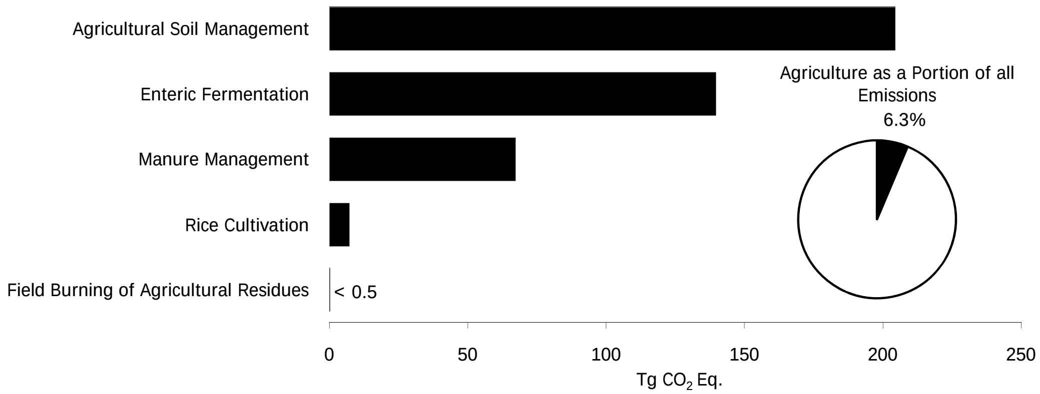
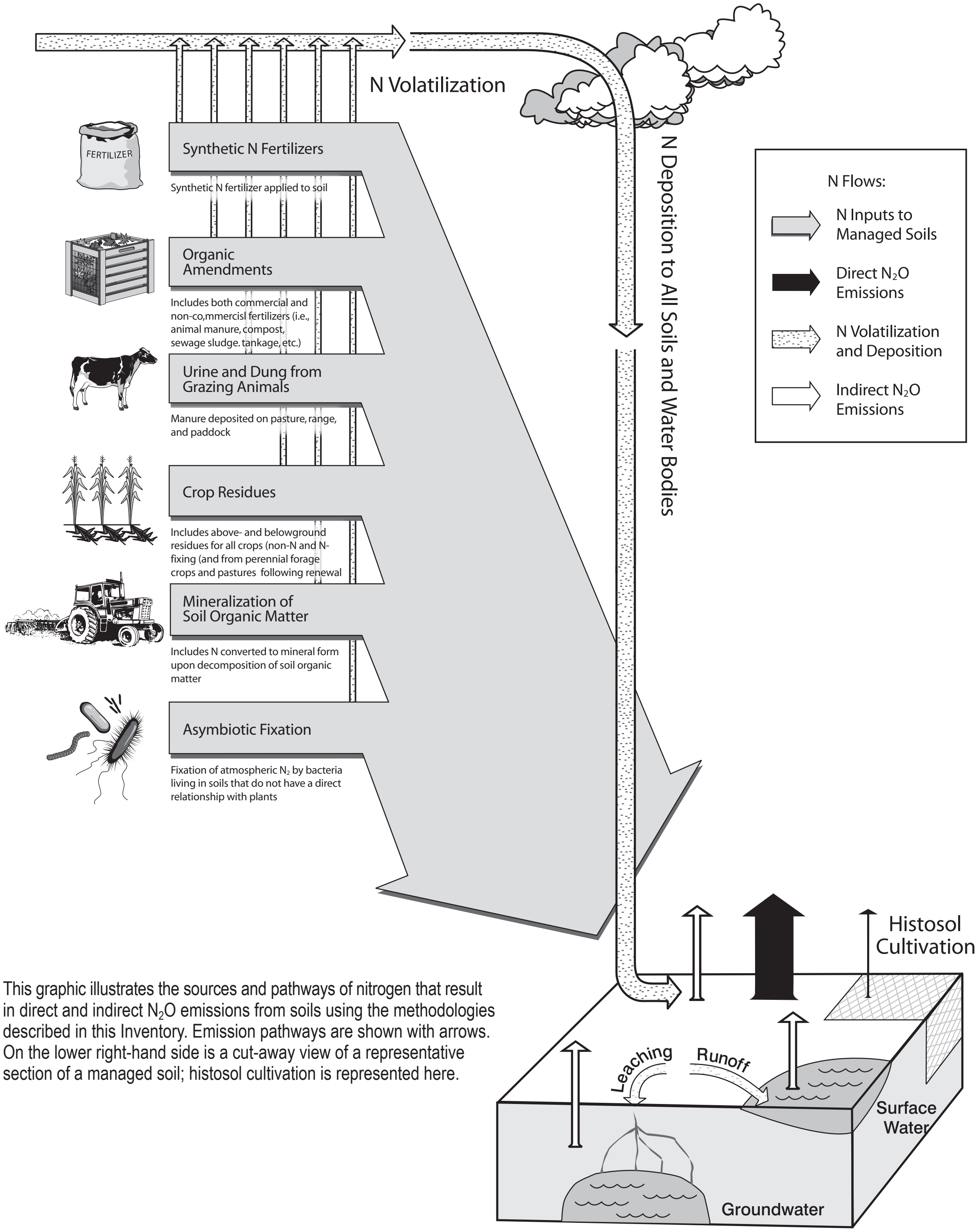


Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Sources

Figure 6-2

Sources and Pathways of N that Result in N_2O Emissions from Agricultural Soil Management



This graphic illustrates the sources and pathways of nitrogen that result in direct and indirect N_2O emissions from soils using the methodologies described in this Inventory. Emission pathways are shown with arrows. On the lower right-hand side is a cut-away view of a representative section of a managed soil; histosol cultivation is represented here.

Figure 6-3

Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq/year)

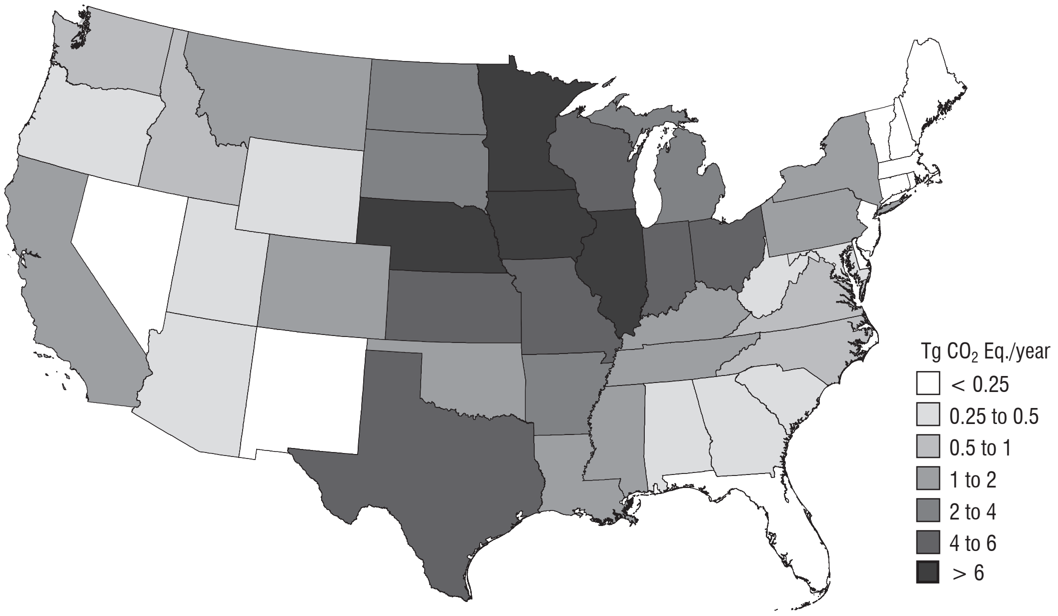


Figure 6-4

Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO_2 Eq./year)

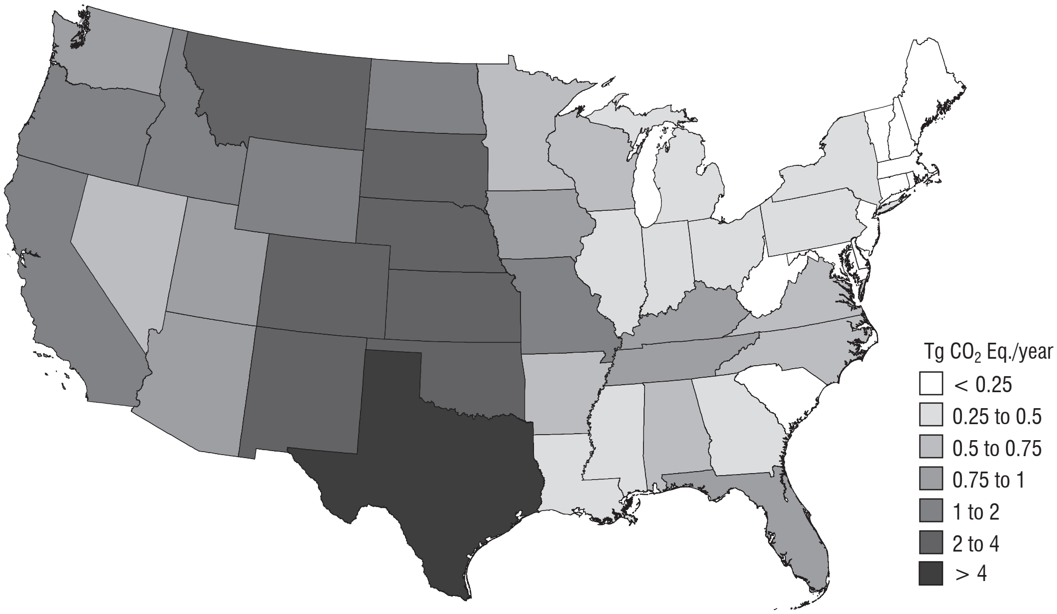


Figure 6-5

Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Using the DAYCENT Model, 1990–2009 (Gg N/year)

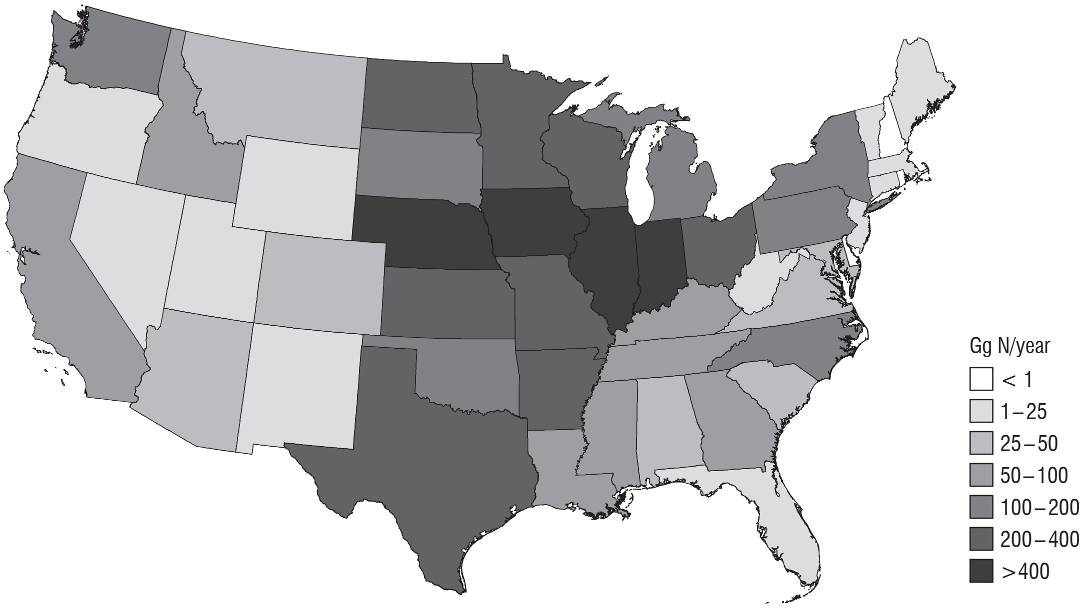


Figure 6-6

Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Using the DAYCENT Model, 1990–2009 (Gg N/year)

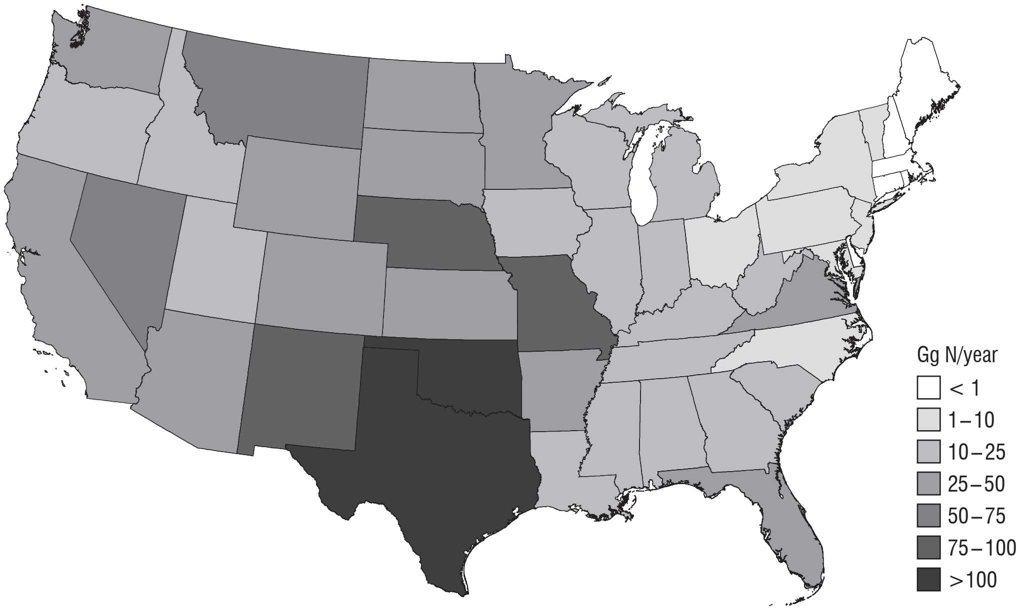
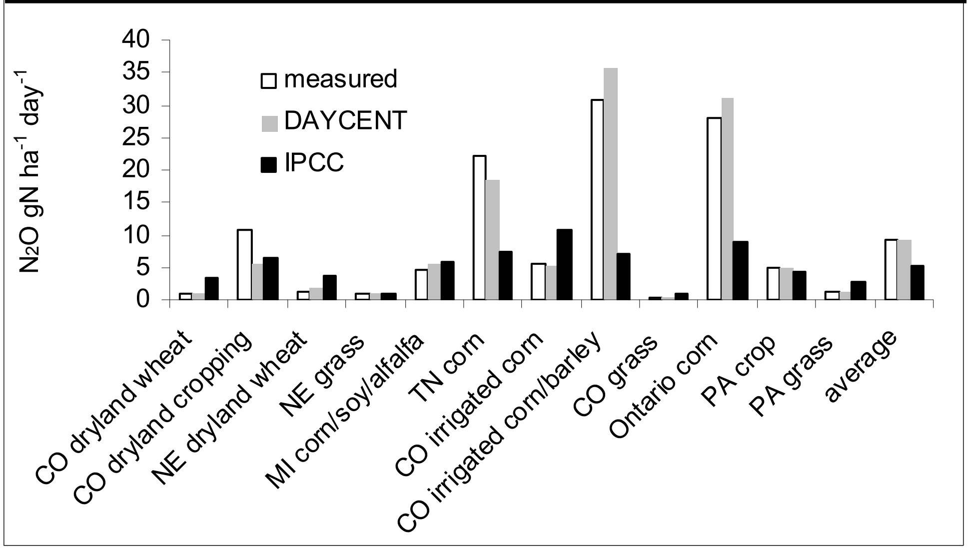


Figure 6-7

Comparison of Measured Emissions at Field Sites with Modeled Emissions Using the DAYCENT Simulation Model



7. Land Use, Land-Use Change, and Forestry

This chapter provides an assessment of the net greenhouse gas flux[155] resulting from the uses and changes in land types and forests in the United States. The Intergovernmental Panel on Climate Change *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) recommends reporting fluxes according to changes within and conversions between certain land-use types termed forest land, cropland, grassland, and settlements (as well as wetlands). The greenhouse gas flux from *Forest Land Remaining Forest Land* is reported using estimates of changes in forest carbon (C) stocks, non-carbon dioxide (CO_2) emissions from forest fires, and the application of synthetic fertilizers to forest soils. The greenhouse gas flux reported in this chapter from agricultural lands (i.e., cropland and grassland) includes changes in organic C stocks in mineral and organic soils due to land use and management, and emissions of CO_2 due to the application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization. Fluxes are reported for four agricultural land use/land-use change categories: *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland*, and *Land Converted to Grassland*. Fluxes resulting from *Settlements Remaining Settlements* include those from urban trees and soil fertilization. Landfilled yard trimmings and food scraps are accounted for separately under *Other*.

The estimates in this chapter, with the exception of CO_2 fluxes from wood products and urban trees, and CO_2 emissions from liming and urea fertilization, are based on activity data collected at multiple-year intervals, which are in the form of forest, land-use, and municipal solid waste surveys. CO_2 fluxes from forest C stocks (except the wood product components) and from agricultural soils (except the liming component) are calculated on an average annual basis from data collected in intervals ranging from 1 to 10 years. The resulting annual averages are applied to years between surveys. Calculations of non-CO_2 emissions from forest fires are based on forest CO_2 flux data. For the landfilled yard trimmings and food scraps source, periodic solid waste survey data were interpolated so that annual storage estimates could be derived. This flux has been applied to the entire time series, and periodic U.S. census data on changes in urban area have been used to develop annual estimates of CO_2 flux.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO_2 Eq. (276.8 Tg C) (Table 7-1 and Table 7-2). This represents an offset of approximately 15.3 percent of total U.S. CO_2 emissions. Total land use, land-use change, and forestry net C sequestration[156] increased by approximately 17.8 percent between 1990 and 2009. This increase was primarily due to an increase in the rate of net C accumulation in forest C stocks. Net C accumulation in *Forest Land Remaining Forest Land, Land Converted to Grassland*, and *Settlements Remaining Settlements* increased, while net C accumulation in *Cropland Remaining Cropland, Grassland Remaining Grassland*, and landfilled yard trimmings and food scraps slowed over this period. Emissions from *Land Converted to Cropland* increased between 1990 and 2009.

Table 7-1: Net CO_2 Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Sink Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest Land Remaining Forest Land[1]	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements[2]	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	**(861.5)**	**(576.6)**	**(1,056.5)**	**(1,064.3)**	**(1,060.9)**	**(1,040.5)**	**(1,015.1)**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

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[155] The term “flux” is used here to encompass both emissions of greenhouse gases to the atmosphere, and removal of C from the atmosphere. Removal of C from the atmosphere is also referred to as “carbon sequestration.”

[156] Carbon sequestration estimates are net figures. The C stock in a given pool fluctuates due to both gains and losses. When losses exceed gains, the C stock decreases, and the pool acts as a source. When gains exceed losses, the C stock increases, and the pool acts as a sink. This is also referred to as net C sequestration.

[1] Estimates include C stock changes on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.
[2] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

Table 7-2: Net CO_2 Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg C)

Sink Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest Land Remaining Forest Land[1]	(185.7)	(103.2)	(248.6)	(250.2)	(248.7)	(243.0)	(235.4)
Cropland Remaining Cropland	(8.0)	(8.2)	(5.0)	(5.2)	(5.4)	(4.9)	(4.7)
Land Converted to Cropland	0.6	0.6	1.6	1.6	1.6	1.6	1.6
Grassland Remaining Grassland	(14.2)	(14.3)	(2.4)	(2.4)	(2.3)	(2.3)	(2.3)
Land Converted to Grassland	(5.4)	(7.4)	(6.7)	(6.6)	(6.5)	(6.5)	(6.4)
Settlements Remaining Settlements[2]	(15.6)	(21.1)	(23.9)	(24.5)	(25.1)	(25.6)	(26.2)
Other (Landfilled Yard Trimmings and Food Scraps)	(6.6)	(3.6)	(3.1)	(3.0)	(3.0)	(3.1)	(3.4)
Total	**(235.0)**	**(157.3)**	**(288.1)**	**(290.3)**	**(289.3)**	**(283.8)**	**(276.8)**

Note: 1 Tg C = 1 teragram C = 1 million metric tons C. Parentheses indicate net sequestration. Totals may not sum due to independent rounding.
[1] Estimates include C stock changes on both *Forest Land Remaining Forest Land and Land Converted to Forest Land*.
[2] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table 7-3 and Table 7-4. Liming of agricultural soils and urea fertilization in 2009 resulted in CO_2 emissions of 4.2 Tg CO_2 Eq. (4,221 Gg) and 3.6 Tg CO_2 Eq. (3,612 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.1 Tg CO_2 Eq. (1,090 Gg), and nitrous oxide (N_2O) emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2009 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2009 accounted for 1.5 Tg CO_2 Eq. (5 Gg) in 2009. This represents an increase of 55 percent since 1990. Forest fires in 2009 resulted in methane (CH_4) emissions of 7.8 Tg CO_2 Eq. (372 Gg), and in N_2O emissions of 6.4 Tg CO_2 Eq. (21 Gg).

Table 7-3: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Source Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8.1**	**8.8**	**8.9**	**8.8**	**9.2**	**9.6**	**8.9**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH_4	**3.2**	**14.3**	**9.8**	**21.6**	**20.0**	**11.9**	**7.8**
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N_2O	**3.7**	**13.2**	**9.8**	**19.5**	**18.3**	**11.6**	**8.3**
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils[1]	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils[2]	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**15.0**	**36.3**	**28.6**	**49.8**	**47.5**	**33.2**	**25.0**

+ Less than 0.05 Tg CO_2 Eq.
Note: These estimates include direct emissions only. Indirect N_2O emissions are reported in the Agriculture chapter. Totals may

not sum due to independent rounding.
[1] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[2] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

Table 7-4: Emissions from Land Use, Land-Use Change, and Forestry (Gg)

Source Category	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CO_2	**8,117**	**8,768**	**8,933**	**8,754**	**9,214**	**9,646**	**8,922**
Cropland Remaining Cropland: Liming of Agricultural Soils	4,667	4,328	4,349	4,220	4,464	5,042	4,221
Urea Fertilization	2,417	3,214	3,504	3,656	3,738	3,612	3,612
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1,033	1,227	1,079	879	1,012	992	1,090
CH_4	**152**	**682**	**467**	**1,027**	**953**	**569**	**372**
Forest Land Remaining Forest Land: Forest Fires	152	682	467	1,027	953	569	372
N_2O	**12**	**43**	**32**	**63**	**59**	**37**	**27**
Forest Land Remaining Forest Land: Forest Fires	8	38	26	57	53	31	21
Forest Land Remaining Forest Land: Forest Soils[1]	+	1	1	1	1	1	1
Settlements Remaining Settlements: Settlement Soils[2]	3	4	5	5	5	5	5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+

+ Less than 0.5 Gg
Note: These estimates include direct emissions only. Indirect N_2O emissions are reported in the Agriculture chapter. Totals may not sum due to independent rounding.
[1] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[2] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

[BEGIN BOX]

Box 7-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[157] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[158] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

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[157] See http://www.ipcc-nggip.iges.or.jp/public/index.html.

[158] See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

7.1. Representation of the U.S. Land Base

A national land-use categorization system that is consistent and complete both temporally and spatially is needed in order to assess land use and land-use change status and the associated greenhouse gas fluxes over the inventory time series. This system should be consistent with IPCC (2006), such that all countries reporting on national greenhouse gas fluxes to the UNFCCC should (1) describe the methods and definitions used to determine areas of managed and unmanaged lands in the country, (2) describe and apply a consistent set of definitions for land-use categories over the entire national land base and time series associated with the greenhouse gas inventory, such that increases in the land areas within particular land-use categories are balanced by decreases in the land areas of other categories, and (3) account for greenhouse gas fluxes on all managed lands. The implementation of such a system helps to ensure that estimates of greenhouse gas fluxes are as accurate as possible. This section of the Inventory has been developed in order to comply with this guidance.

Multiple databases are used to track land management in the United States, which are also used as the basis to classify U.S. land area into the six IPCC land-use categories (i.e., *Forest Land Remaining Forest Land*, *Cropland Remaining Cropland*, *Grassland Remaining Grassland*, *Wetlands Remaining Wetlands*, *Settlements Remaining Settlements* and *Other Land Remaining Other Land*) and thirty land-use change categories (e.g., *Cropland Converted to Forest Land*, *Grassland Converted to Forest Land*, *Wetlands Converted to Forest Land*, *Settlements Converted to Forest Land*, *Other Land Converted to Forest Lands*)[159] (IPCC 2006). The primary databases are the U.S. Department of Agriculture (USDA) National Resources Inventory (NRI)[160] and the USDA Forest Service (USFS) Forest Inventory and Analysis (FIA)[161] Database. The U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD)[162] is also used to identify land uses in regions that were not included in the NRI or FIA. The total land area included in the U.S. Inventory is 786 million hectares, and this entire land base is considered managed.[163] In 2009, the United States had a total of 274 million hectares of Forest Land (a 4 percent increase since 1990), 163 million hectares of Cropland (down 4.4 percent since 1990), 258 million hectares of Grassland (down 4.2 percent since 1990), 26 million hectares of Wetlands (down 4.9 percent since 1990), 49 million hectares of Settlements (up 24.5 percent since 1990), and 14 million hectares of Other Land. It is important to note that the land base formally classified for the Inventory (see Table 7-5) is considered managed. Alaska is not formally included in the current land representation, but there is a planned improvement underway to include this portion of the United States in future inventories. In addition, wetlands are not differentiated between managed and unmanaged, although some wetlands would be unmanaged according to the U.S. definition (see definition later in this section). Future improvements will include a differentiation between managed and unmanaged wetlands. In addition, carbon stock changes are not currently estimated for the entire land base, which leads to discrepancies between the area data presented here and in the subsequent sections of the NIR. Planned improvements are underway or in development phases to conduct an inventory of carbon stock changes on all managed land (e.g., federal grasslands).

Dominant land uses vary by region, largely due to climate patterns, soil types, geology, proximity to coastal regions, and historical settlement patterns, although all land-uses occur within each of the fifty states (Figure 7-1). Forest Land tends to be more common in the eastern states, mountainous regions of the western United States, and Alaska. Cropland is concentrated in the mid-continent region of the United States, and Grassland is more common in the western United States. Wetlands are fairly ubiquitous throughout the United States, though they are more common in the upper Midwest and eastern portions of the country. Settlements are more concentrated along the coastal margins and in the eastern states.

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[159] Land-use category definitions are provided in the Methodology section.

[160] NRI data is available at <http://www.ncgc.nrcs.usda.gov/products/nri/index.html>.

[161] FIA data is available at <http://fia.fs.fed .us/tools-data/data/>.

[162] NLCD data is available at <http://www.mrlc.gov/>.

[163] The current land representation does not include areas from Alaska or U.S. territories, but there are planned improvements to include these regions in future reports.

Table 7-5: Size of Land Use and Land-Use Change Categories on Managed Land Area by Land Use and Land Use Change Categories (thousands of hectares)

Land Use & Land-Use Change Categories[a]	1990	2000	2005	2006	2007	2008	2009
Total Forest Land	**263,878**	**268,790**	**271,322**	**272,107**	**272,891**	**273,677**	**274,462**
FF	257,180	253,080	255,444	256,181	256,917	257,655	258,392
CF	1,266	2,793	2,976	2,983	2,991	2,998	3,006
GF	4,879	11,347	11,122	11,157	11,193	11,229	11,264
WF	63	201	205	205	206	207	207
SF	101	268	303	304	305	306	307
OF	389	1,102	1,273	1,276	1,279	1,282	1,285
Total Cropland	**170,632**	**164,401**	**163,192**	**163,178**	**163,164**	**163,151**	**163,137**
CC	155,433	144,004	145,531	145,518	145,506	145,493	145,481
FC	1,105	1,101	805	804	803	802	802
GC	13,298	17,834	15,513	15,513	15,513	15,512	15,512
WC	163	264	234	234	234	234	234
SC	470	886	825	825	825	825	825
OC	162	311	283	283	283	283	283
Total Grassland	**269,643**	**263,092**	**260,565**	**260,012**	**259,458**	**258,904**	**258,350**
GG	260,064	245,460	243,839	243,395	242,951	242,506	242,061
FG	1,463	3,048	2,787	2,773	2,759	2,745	2,730
CG	7,502	13,303	12,632	12,541	12,451	12,360	12,270
WG	230	373	339	338	338	337	336
SG	129	255	255	253	252	250	249
OG	255	653	714	712	709	706	704
Total Wetlands	**27,788**	**27,560**	**27,173**	**26,983**	**26,793**	**26,603**	**26,412**
WW	27,179	26,155	25,701	25,519	25,338	25,157	24,976
FW	138	378	401	398	395	393	390
CW	134	348	351	348	344	341	338
GW	286	633	675	672	670	668	665
SW	<1	3	3	3	3	3	3
OW	51	43	43	42	42	42	42
Total Settlements	**39,518**	**47,558**	**49,247**	**49,238**	**49,229**	**49,220**	**49,212**
SS	34,742	34,055	34,975	34,966	34,958	34,949	34,941
FS	1,842	5,480	5,872	5,872	5,872	5,871	5,871
CS	1,373	3,599	3,673	3,672	3,672	3,672	3,672
GS	1,498	4,183	4,479	4,479	4,479	4,479	4,479
WS	3	29	32	32	32	32	32
OS	60	212	217	217	217	217	217
Total Other Land	**14,385**	**14,443**	**14,346**	**14,327**	**14,309**	**14,290**	**14,272**
OO	13,397	12,286	12,104	12,087	12,069	12,051	12,033
FO	193	506	559	559	559	559	559
CO	279	440	499	499	499	499	499
GO	458	1,085	1,058	1,057	1,057	1,056	1,056
WO	55	115	114	114	114	114	113
SO	3	11	12	12	12	12	12
Grand Total	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**	**785,845**

[a] The abbreviations are "F" for Forest Land, "C" for Cropland, "G" for Grassland, "W" for Wetlands, "S" for Settlements, and "O" for Other Lands. Lands remaining in the same land use category are identified with the land use abbreviation given twice (e.g., "FF" is Forest Land Remaining Forest Land), and land use change categories are identified with the previous land use abbreviation followed by the new land use abbreviation (e.g., "CF" is Cropland Converted to Forest Land).

Notes: All land areas reported in this table are considered managed. A planned improvement is underway to deal with an exception for wetlands which includes both managed and unmanaged lands based on the definitions for the current U.S. Land Representation Assessment. In addition, U.S. Territories have not been classified into land uses and are not included in the U.S. Land Representation Assessment. See Planned Improvements for discussion on plans to include Alaska and territories in future Inventories.

Figure 7-1. Percent of Total Land Area in the General Land-Use Categories for 2009

Methodology

IPCC Approaches for Representing Land Areas

IPCC (2006) describes three approaches for representing land areas. Approach 1 provides data on the total area for each individual land-use category, but does not provide detailed information on changes of area between categories and is not spatially explicit other than at the national or regional level. With Approach 1, total net conversions between categories can be detected, but not the individual changes between the land-use categories that led to those net changes. Approach 2 introduces tracking of individual land-use changes between the categories (e.g., Forest Land to Cropland, Cropland to Forest Land, Grassland to Cropland, etc.), using surveys or other forms of data that do not provide location data on specific parcels of land. Approach 3 extends Approach 2 by providing location data on specific parcels of land, such as maps, along with the land-use history. The three approaches are not presented as hierarchical tiers and are not mutually exclusive.

According to IPCC (2006), the approach or mix of approaches selected by an inventory agency should reflect calculation needs and national circumstances. For this analysis, the NRI, FIA, and the NLCD have been combined to provide a complete representation of land use for managed lands. These data sources are described in more detail later in this section. All of these datasets have a spatially-explicit time series of land-use data, and therefore Approach 3 is used to provide a full representation of land use in the U.S. Inventory. Lands are treated as remaining in the same category (e.g., *Cropland Remaining Cropland*) if a land-use change has not occurred in the last 20 years. Otherwise, the land is classified in a land-use-change category based on the current use and most recent use before conversion to the current use (e.g., *Cropland Converted to Forest Land*).

Definitions of Land Use in the United States

Managed and Unmanaged Land

The U.S. definitions of managed and unmanaged lands are similar to the basic IPCC (2006) definition of managed land, but with some additional elaboration to reflect national circumstances. Based on the following definitions, most lands in the United States are classified as managed:

- *Managed Land*: Land is considered managed if direct human intervention has influenced its condition. Direct intervention includes altering or maintaining the condition of the land to produce commercial or non-commercial products or services; to serve as transportation corridors or locations for buildings, landfills, or other developed areas for commercial or non-commercial purposes; to extract resources or facilitate acquisition of resources; or to provide social functions for personal, community or societal objectives. Managed land also includes legal protection of lands (e.g., wilderness, preserves, parks, etc.) for conservation purposes (i.e., meets societal objectives).[164]
- *Unmanaged Land*: All other land is considered unmanaged. Unmanaged land is largely comprised of areas inaccessible to human intervention due to the remoteness of the locations, or lands with essentially no development interest or protection due to limited personal, commercial or social value. Though these lands may be influenced indirectly by human actions such as atmospheric deposition of chemical species

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[164] Wetlands are an exception to this general definition, because these lands, as specified by IPCC (2006), are only considered managed if they are created through human activity, such as dam construction, or the water level is artificially altered by human activity. Distinguishing between managed and unmanaged wetlands is difficult, however, due to limited data availability. Wetlands are not characterized by use within the NRI. Therefore, unless wetlands are managed for cropland or grassland, it is not possible to know if they are artificially created or if the water table is managed based on the use of NRI data. See the Planned Improvements section of the Inventory for work being done to refine the Wetland area estimates.

produced in industry, they are not influenced by a direct human intervention.[165]

Land-Use Categories

As with the definition of managed lands, IPCC (2006) provides general non-prescriptive definitions for the six main land-use categories: Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land. In order to reflect U.S. circumstances, country-specific definitions have been developed, based predominantly on criteria used in the land-use surveys for the United States. Specifically, the definition of Forest Land is based on the FIA definition of forest,[166] while definitions of Cropland, Grassland, and Settlements are based on the NRI.[167] The definitions for Other Land and Wetlands are based on the IPCC (2006) definitions for these categories.

- *Forest Land*: A land-use category that includes areas at least 36.6 m wide and 0.4 ha in size with at least 10 percent cover (or equivalent stocking) by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated. Forest land includes transition zones, such as areas between forest and non-forest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Roadside, streamside, and shelterbelt strips of trees must have a crown width of at least 36.6 m and continuous length of at least 110.6 m to qualify as forest land. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 36.6 m wide or 0.4 ha in size, otherwise they are excluded from Forest Land and classified as Settlements. Tree-covered areas in agricultural production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forest land (Smith et al. 2009). NOTE: This definition applies to all U.S. lands and territories. However, at this time, data availability is limited for remote or inaccessible areas such as interior Alaska

- *Cropland*: A land-use category that includes areas used for the production of adapted crops for harvest; this category includes both cultivated and non-cultivated lands.[168] Cultivated crops include row crops or close-grown crops and also hay or pasture in rotation with cultivated crops. Non-cultivated cropland includes continuous hay, perennial crops (e.g., orchards) and horticultural cropland. Cropland also includes land with alley cropping and windbreaks,[169] as well as lands in temporary fallow or enrolled in conservation reserve programs (i.e., set-asides[170]). Roads through Cropland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Cropland area estimates and are, instead, classified as Settlements.

- *Grassland*: A land-use category on which the plant cover is composed principally of grasses, grass-like plants, forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands.[171] This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Savannas, some wetlands and deserts, in addition to tundra are considered Grassland.[172] Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices such as silvipasture and windbreaks, assuming the stand or woodlot does not meet the criteria for Forest Land. Roads through

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[165] There will be some areas that qualify as Forest Land or Grassland according to the land use criteria, but are classified as unmanaged land due to the remoteness of their location.

[166] See <http://socrates.lv-hrc.nevada.edu/fia/ab/issues/pending/glossary/Glossary_5_30_06.pdf>.

[167] See <http://www.nrcs.usda.gov/technical/land/nri01/glossary.html>.

[168] A minor portion of Cropland occurs on federal lands, and is not currently included in the C stock change inventory. A planned improvement is underway to include these areas in future C inventories.

[169] Currently, there is no data source to account for biomass C stock change associated with woody plant growth and losses in alley cropping systems and windbreaks in cropping systems, although these areas are included in the cropland land base.

[170] A set-aside is cropland that has been taken out of active cropping and converted to some type of vegetative cover, including, for example, native grasses or trees.

[171] Grasslands on federal lands are included in the managed land base, but C stock changes are not estimated on these lands. Federal grassland areas have been assumed to have negligible changes in C due to limited land use and management change, but planned improvements are underway to further investigate this issue and include these areas in future C inventories.

[172] IPCC (2006) guidelines do not include provisions to separate desert and tundra as land categories.

Grassland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Grassland area estimates and are, instead, classified as Settlements.

- *Wetlands*: A land-use category that includes land covered or saturated by water for all or part of the year. Managed Wetlands are those where the water level is artificially changed, or were created by human activity. Certain areas that fall under the managed Wetlands definition are covered in other areas of the IPCC guidance and/or the inventory, including Cropland (e.g., rice cultivation), Grassland, and Forest Land (including drained or undrained forested wetlands).
- *Settlements*: A land-use category representing developed areas consisting of units of 0.25 acres (0.1 ha) or more that includes residential, industrial, commercial, and institutional land; construction sites; public administrative sites; railroad yards; cemeteries; airports; golf courses; sanitary landfills; sewage treatment plants; water control structures and spillways; parks within urban and built-up areas; and highways, railroads, and other transportation facilities. Also included are tracts of less than 10 acres (4.05 ha) that may meet the definitions for Forest Land, Cropland, Grassland, or Other Land but are completely surrounded by urban or built-up land, and so are included in the settlement category. Rural transportation corridors located within other land uses (e.g., Forest Land, Cropland) are also included in Settlements.
- *Other Land*: A land-use category that includes bare soil, rock, ice, non-settlement transportation corridors, and all land areas that do not fall into any of the other five land-use categories. It allows the total of identified land areas to match the managed national area.

Land-Use Data Sources: Description and Application to U.S. Land Area Classification

U.S. Land-Use Data Sources

The three main data sources for land area and use data in the United States are the NRI, FIA, and the NLCD. For the Inventory, the NRI is the official source of data on all land uses on non-federal lands (except forest land), and is also used as the resource to determine the total land base for the conterminous United States and Hawaii. The NRI is conducted by the USDA Natural Resources Conservation Service and is designed to assess soil, water, and related environmental resources on non-federal lands. The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the U.S. Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit (typically a 160-acre [64.75 ha] square quarter-section), three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). The NRI survey utilizes data derived from remote sensing imagery and site visits in order to provide detailed information on land use and management, particularly for croplands and grasslands, and is used as the basis to account for C stock changes in agricultural lands (except federal Grasslands). The NRI survey was conducted every 5 years between 1982 and 1997, but shifted to annualized data collection in 1998. This Inventory incorporates data through 2003 from the NRI.

The FIA program, conducted by the USFS, is the official source of data on Forest Land area and management data for the Inventory. FIA engages in a hierarchical system of sampling, with sampling categorized as Phases 1 through 3, in which sample points for phases are subsets of the previous phase. Phase 1 refers to collection of remotely-sensed data (either aerial photographs or satellite imagery) primarily to classify land into forest or non-forest and to identify landscape patterns like fragmentation and urbanization. Phase 2 is the collection of field data on a network of ground plots that enable classification and summarization of area, tree, and other attributes associated with forest land uses. Phase 3 plots are a subset of Phase 2 plots where data on indicators of forest health are measured. Data from all three phases are also used to estimate C stock changes for forest land. Historically, FIA inventory surveys had been conducted periodically, with all plots in a state being measured at a frequency of every 5 to 14 years. A new national plot design and annual sampling design was introduced by FIA about ten years ago. Most states, though, have only recently been brought into this system. Annualized sampling means that a portion of plots throughout each state is sampled each year, with the goal of measuring all plots once every 5 years. See Annex 3.12 to see the specific survey data available by state. The most recent year of available data varies state by state (2002 through 2009).

Though NRI provides land-area data for both federal and non-federal lands, it only includes land-use data on non-federal lands, and FIA only records data for forest land.[173] Consequently, major gaps exist when the datasets are combined, such as federal grassland operated by the Bureau of Land Management (BLM), USDA, and National Park Service, as well as most of Alaska.[174] The NLCD is used as a supplementary database to account for land use on federal lands that are not included in the NRI and FIA databases. The NLCD land-cover classification scheme, available for 1992 and 2001, has been applied over the conterminous United States (Homer et al. 2007). The 2001 product also provides land use data that has been used for Hawaii federal lands. For this analysis, the NLCD Retrofit Land Cover Change Product was used in order to represent both land use and land-use change for federal lands in the conterminous U.S. (Homer et al. 2007). It is based primarily on Landsat Thematic Mapper imagery. The NLCD contains 21 categories of land-cover information, which have been aggregated into the IPCC land-use categories, and the data are available at a spatial resolution of 30 meters. The federal land portion of the NLCD was extracted from the dataset using the federal land area boundary map from the National Atlas (2005). This map represents federal land boundaries in 2005, so as part of the analysis, the federal land area was adjusted annually based on the NRI federal land area estimates (i.e., land is periodically transferred between federal and non-federal ownership). Consequently, the portion of the land base categorized with NLCD data varied from year to year, corresponding to an increase or decrease in the federal land base. The NLCD is strictly a source of land-cover information, however, and does not provide the necessary site conditions, crop types, and management information from which to estimate C stock changes on those lands.

Another step in the analysis is to address gaps as well as overlaps in the representation of the U.S. land base between the Agricultural Carbon Stock Inventory (*Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*) and Forest Land Carbon Stock Inventory (*Forest Land Remaining Forest Land* and *Land Converted to Forest Land*), which are based on the NRI and FIA databases, respectively. NRI and FIA have different criteria for classifying forest land and sampling designs, leading to discrepancies in the resulting estimates of Forest Land area on non-federal land. Similarly, there are discrepancies between the NLCD and FIA data for defining and classifying Forest Land on federal lands. Moreover, dependence exists between the Forest Land area and the amount of land designated as other land uses in both the NRI and the NLCD, such as the amount of Grassland, Cropland, and Wetlands, relative to the Forest Land area. This results in inconsistencies among the three databases for estimated Forest Land area, as well as for the area estimates for other land-use categories. FIA is the main database for forest statistics, and consequently, the NRI and NLCD were adjusted to achieve consistency with FIA estimates of Forest Land. The adjustments were made at a state-scale, and it was assumed that the majority of the discrepancy in forest area was associated with an under- or over-prediction of Grassland and Wetland area in the NRI and NLCD due to differences in Forest Land definitions. Specifically, the Forest Land area for a given state according to the NRI and NLCD was adjusted to match the FIA estimates of Forest Land for non-federal and federal land, respectively. In a second step, corresponding increases or decreases were made in the area estimates of Grassland and Wetland from the NRI and NLCD, in order to balance the change in forest area, and therefore not change the overall amount of managed land within an individual state. The adjustments were based on the proportion of land within each of these land-use categories at the state-level. (i.e., a higher proportion of Grassland led to a larger adjustment in Grassland area).

As part of Quality Assurance /Quality Control (QA/QC), the land base derived from the NRI, FIA and NLCD was compared to the Topologically Integrated Geographic Encoding and Referencing (TIGER) survey (U.S. Census Bureau 2010). The U.S. Census Bureau gathers data on the U.S. population and economy, and has a database of land areas for the country. The land area estimates from the U.S. Census Bureau differ from those provided by the land-use surveys used in the Inventory because of discrepancies in the reporting approach for the census and the methods used in the NRI, FIA, and NLCD. The area estimates of land-use categories, based on NRI, FIA, and NLCD, are derived from remote sensing data instead of the land survey approach used by the U.S. Census Survey. More importantly, the U.S. Census Survey does not provide a time series of land-use change data or land management information, which is critical for conducting emission inventories and is provided from the NRI and FIA surveys. Consequently, the U.S. Census Survey was not adopted as the official land area estimate for the Inventory. Rather, the NRI data were adopted because this database provides full coverage of land area and land use

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[173] FIA does collect some data on non-forest land use, but these are held in regional databases versus the national database. The status of these data is being investigated.

[174] The survey programs also do not include U.S. Territories with the exception of non-federal lands in Puerto Rico, which are included in the NRI survey. Furthermore, NLCD does not include coverage for U.S. Territories.

for the conterminous United States and Hawaii. Regardless, the total difference between the U.S. Census Survey and the data sources used in the Inventory is about 25 million hectares for the total land base of about 786 million hectares currently included in the Inventory, or a 3.1 percent difference. Much of this difference is associated with open waters in coastal regions and the Great Lakes. NRI does not include as much of the area of open waters in these regions as the U.S. Census Survey.

Approach for Combining Data Sources

The managed land base in the United States has been classified into the six IPCC land-use categories using definitions[175] developed to meet national circumstances, while adhering to IPCC (2006). In practice, the land was initially classified into a variety of land-use categories using the NRI, FIA and NLCD, and then aggregated into the thirty-six broad land use and land-use-change categories identified in IPCC (2006). Details on the approach used to combine data sources for each land use are described below as are the gaps that will be reconciled as part of ongoing planned improvements:

- *Forest Land*: Both non-federal and federal forest lands in both the continental United States and coastal Alaska are covered by FIA. FIA is used as the basis for both Forest Land area data as well as to estimate C stocks and fluxes on Forest Land. Interior Alaska is not currently surveyed by FIA, but NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports. Forest Lands in U.S. territories are currently excluded from the analysis, but FIA surveys are currently being conducted on U.S. territories and will become available in the future. NRI is being used in the current report to provide Forest Land areas on non-federal lands in Hawaii. Currently, federal forest land in Hawaii is evaluated with the 2001 NLCD, but FIA data will be collected in Hawaii in the future.
- *Cropland*: Cropland is classified using the NRI, which covers all non-federal lands within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Cropland area data as well as to estimate C stocks and fluxes on Cropland. Croplands in U.S. territories are excluded from both NRI data collection and the NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.
- *Grassland*: Grassland on non-federal lands is classified using the NRI within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Grassland area data as well as to estimate C stocks and fluxes on Grassland. U.S. territories are excluded from both NRI data collection and the current release of the NLCD product. Grassland on federal Bureau of Land Management lands, Department of Defense lands, National Parks and within USFS lands are covered by the NLCD. In addition, federal and non-federal grasslands in Alaska are currently excluded from the analysis, but NLCD has a new product for Alaska that will be incorporated into the assessment for future reports.
- *Wetlands*: NRI captures wetlands on non-federal lands within 49 states (excluding Alaska), while federal wetlands are covered by the NLCD. Alaska and U.S. territories are excluded. This currently includes both managed and unmanaged wetlands as no database has yet been applied to make this distinction. See Planned Improvements for details.
- *Settlements*: The NRI captures non-federal settlement area in 49 states (excluding Alaska). If areas of Forest Land or Grassland under 10 acres (4.05 ha) are contained within settlements or urban areas, they are classified as Settlements (urban) in the NRI database. If these parcels exceed the 10 acre (4.05 ha) threshold and are Grassland, they will be classified as such by NRI. Regardless of size, a forested area is classified as non-forest by FIA if it is located within an urban area. Settlements on federal lands are covered by NLCD. Settlements in U.S. territories are currently excluded from NRI and NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.
- *Other Land*: Any land not falling into the other five land categories and, therefore, categorized as Other Land is classified using the NRI for non-federal areas in the 49 states (excluding Alaska) and NLCD for the federal lands. Other land in U.S. territories is excluded from the NLCD. NLCD has a new product for

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[175] Definitions are provided in the previous section.

Alaska that will be incorporated into the assessment as a planned improvement for future reports.

Some lands can be classified into one or more categories due to multiple uses that meet the criteria of more than one definition. However, a ranking has been developed for assignment priority in these cases. The ranking process is initiated by distinguishing between managed and unmanaged lands. The managed lands are then assigned, from highest to lowest priority, in the following manner:

Settlements > Cropland > Forest Land > Grassland > Wetlands > Other Land

Settlements are given the highest assignment priority because they are extremely heterogeneous with a mosaic of patches that include buildings, infrastructure and travel corridors, but also open grass areas, forest patches, riparian areas, and gardens. The latter examples could be classified as Grassland, Forest Land, Wetlands, and Cropland, respectively, but when located in close proximity to settlement areas they tend to be managed in a unique manner compared to non-settlement areas. Consequently, these areas are assigned to the Settlements land-use category. Cropland is given the second assignment priority, because cropping practices tend to dominate management activities on areas used to produce food, forage or fiber. The consequence of this ranking is that crops in rotation with grass will be classified as Cropland, and land with woody plant cover that is used to produce crops (e.g., orchards) is classified as Cropland, even though these areas may meet the definitions of Grassland or Forest Land, respectively. Similarly, Wetlands are considered Croplands if they are used for crop production, such as rice or cranberries. Forest Land occurs next in the priority assignment because traditional forestry practices tend to be the focus of the management activity in areas with woody plant cover that are not croplands (e.g., orchards) or settlements (e.g., housing subdivisions with significant tree cover). Grassland occurs next in the ranking, while Wetlands and Other Land complete the list.

The assignment priority does not reflect the level of importance for reporting greenhouse gas emissions and removals on managed land, but is intended to classify all areas into a single land use. Currently, the IPCC does not make provisions in the guidelines for assigning land to multiple uses. For example, a Wetland is classified as Forest Land if the area has sufficient tree cover to meet the stocking and stand size requirements. Similarly, Wetlands are classified as Cropland if they are used for crop production, such as rice or cranberries. In either case, emissions from Wetlands are included in the Inventory if human interventions are influencing emissions from Wetlands, in accordance with the guidance provided in IPCC (2006).

Recalculations Discussion

No major revisions were made to the time series for the current Inventory. However, new data were incorporated from FIA on forestland areas, which was used to make minor adjustments to the time series. FIA conducts a survey of plots annually so that each plot is visited every 5 years (Note: some states have not initiated the annual sampling regime, as discussed previously). Consequently, the time series is updated each year as new data are collected over the 5 year cycles.

Planned Improvements

Area data by land-use category are not estimated for major portions of Alaska or any of the U.S. territories. A key planned improvement is to incorporate land-use data from these areas into the Inventory. For Alaska, a new NLCD 2001 data product will be used to cover those land areas presently omitted. Fortunately, most of the managed land in the United States is included in the current land-use statistics, but a complete accounting is a key goal for the near future. Data sources will also be evaluated for representing land use on federal and non-federal lands in U.S. territories.

Additional work will be conducted to reconcile differences in Forest Land estimates between the NRI and FIA, evaluating the assumption that the majority of discrepancies in Forest Land areas are associated with an over- or under-estimation of Grassland and Wetland area. In some regions of the United States, a discrepancy in Forest Land areas between NRI and FIA may be associated with an over- or under-prediction of other land uses, and an analysis is planned to develop region-specific adjustments.

There are also other databases that may need to be reconciled with the NRI and NLCD datasets, particularly for Settlements and Wetlands. Urban area estimates, used to produce C stock and flux estimates from urban trees, are currently based on population data (1990 and 2000 U.S. Census data). Using the population statistics, “urban clusters” are defined as areas with more than 500 people per square mile. The USFS is currently moving ahead with an urban forest inventory program so that urban forest area estimates will be consistent with FIA forest area estimates outside of urban areas, which would be expected to reduce omissions and overlap of forest area estimates along urban boundary areas.

7.2. Forest Land Remaining Forest Land

Changes in Forest Carbon Stocks (IPCC Source Category 5A1)

For estimating C stocks or stock change (flux), C in forest ecosystems can be divided into the following five storage pools (IPCC 2003):

- Aboveground biomass, which includes all living biomass above the soil including stem, stump, branches, bark, seeds, and foliage. This category includes live understory.
- Belowground biomass, which includes all living biomass of coarse living roots greater than 2 mm diameter.
- Dead wood, which includes all non-living woody biomass either standing, lying on the ground (but not including litter), or in the soil.
- Litter, which includes the litter, fumic, and humic layers, and all non-living biomass with a diameter less than 7.5 cm at transect intersection, lying on the ground.
- Soil organic C (SOC), including all organic material in soil to a depth of 1 meter but excluding the coarse roots of the aboveground pools.

In addition, there are two harvested wood pools necessary for estimating C flux:

- Harvested wood products (HWP) in use.
- HWP in solid waste disposal sites (SWDS).

C is continuously cycled among these storage pools and between forest ecosystems and the atmosphere as a result of biological processes in forests (e.g., photosynthesis, respiration, growth, mortality, decomposition, and disturbances such as fires or pest outbreaks) and anthropogenic activities (e.g., harvesting, thinning, clearing, and replanting). As trees photosynthesize and grow, C is removed from the atmosphere and stored in living tree biomass. As trees die and otherwise deposit litter and debris on the forest floor, C is released to the atmosphere or transferred to the soil by organisms that facilitate decomposition.

The net change in forest C is not equivalent to the net flux between forests and the atmosphere because timber harvests do not cause an immediate flux of C of all vegetation C to the atmosphere. Instead, harvesting transfers a portion of the C stored in wood to a "product pool." Once in a product pool, the C is emitted over time as CO_2 when the wood product combusts or decays. The rate of emission varies considerably among different product pools. For example, if timber is harvested to produce energy, combustion releases C immediately. Conversely, if timber is harvested and used as lumber in a house, it may be many decades or even centuries before the lumber decays and C is released to the atmosphere. If wood products are disposed of in SWDS, the C contained in the wood may be released many years or decades later, or may be stored almost permanently in the SWDS.

This section quantifies the net changes in C stocks in the five forest C pools and two harvested wood pools. The net change in stocks for each pool is estimated, and then the changes in stocks are summed over all pools to estimate total net flux. The focus on C implies that all C-based greenhouse gases are included, and the focus on stock change suggests that specific ecosystem fluxes do not need to be separately itemized in this report. Disturbances from forest fires and pest outbreaks are implicitly included in the net changes. For instance, an inventory conducted after fire counts only the trees that are left. The change between inventories thus accounts for the C changes due to fires; however, it may not be possible to attribute the changes to the disturbance specifically. The IPCC (2003) recommends reporting C stocks according to several land-use types and conversions, specifically *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. Currently, consistent datasets are just becoming available for the conterminous United States to allow forest land conversions and forest land remaining forest land to be identified, and research is ongoing to properly use that information based on research results. Thus, net changes in all forest-related land, including non-forest land converted to forest and forests converted to non-forest, are reported here.

Forest C storage pools, and the flows between them via emissions, sequestration, and transfers, are shown in Figure 7-2. In the figure, boxes represent forest C storage pools and arrows represent flows between storage pools or between storage pools and the atmosphere. Note that the boxes are not identical to the storage pools identified in this chapter. The storage pools identified in this chapter have been refined in this graphic to better illustrate the processes that result in transfers of C from one pool to another, and emissions to as well as uptake from the atmosphere.

Figure 7-2: Forest Sector Carbon Pools and Flows

Approximately 33 percent (304 million hectares) of the U.S. land area is forested (Smith et al. 2009). The current forest carbon inventory includes 271 million hectares in the conterminous 48 states (USDA Forest Service 2010a, 2010b) that are considered managed and are included in this inventory. An additional 6.1 million hectares of southeast and south central Alaskan forest are inventoried and are included here. Three notable differences exist in forest land defined in Smith et al. (2009) and the forest land included in this report, which is based on USDA Forest Service (2010b). Survey data are not yet available from Hawaii and a large portion of interior Alaska, but estimates of these areas are included in Smith et al. (2009). Alternately, survey data for west Texas has only recently become available, and these forests contribute to overall carbon stock reported below. While Hawaii and U.S. territories have relatively small areas of forest land and will thus probably not influence the overall C budget substantially, these regions will be added to the C budget as sufficient data become available. Agroforestry systems are also not currently accounted for in the inventory, since they are not explicitly inventoried by either the Forest Inventory and Analysis (FIA) program of the U.S. Department of Agriculture (USDA) Forest Service or the National Resources Inventory (NRI) of the USDA Natural Resources Conservation Service (Perry et al. 2005).

Sixty-eight percent of U.S. forests (208 million hectares) are classified as timberland, meaning they meet minimum levels of productivity. Nine percent of Alaska forests overall and 81 percent of forests in the conterminous United States are classified as timberlands. Of the remaining nontimberland forests, 30 million hectares are reserved forest lands (withdrawn by law from management for production of wood products) and 66 million hectares are lower productivity forest lands (Smith et al. 2009). Historically, the timberlands in the conterminous 48 states have been more frequently or intensively surveyed than other forest lands.

Forest land area declined by approximately 10 million hectares over the period from the early 1960s to the late 1980s. Since then, forest area has increased by about 12 million hectares. Current trends in forest area represent average annual change of less than 0.2 percent. Given the low rate of change in U.S. forest land area, the major influences on the current net C flux from forest land are management activities and the ongoing impacts of previous land-use changes. These activities affect the net flux of C by altering the amount of C stored in forest ecosystems. For example, intensified management of forests that leads to an increased rate of growth increases the eventual biomass density of the forest, thereby increasing the uptake of C.[176] Though harvesting forests removes much of the aboveground C, on average the volume of annual net growth nationwide is about 72 percent higher than the volume of annual removals on timberlands (Smith et al. 2009). The reversion of cropland to forest land increases C storage in biomass, forest floor, and soils. The net effects of forest management and the effects of land-use change involving forest land are captured in the estimates of C stocks and fluxes presented in this chapter.

In the United States, improved forest management practices, the regeneration of previously cleared forest areas, and timber harvesting and use have resulted in net uptake (i.e., net sequestration) of C each year from 1990 through 2009. The rate of forest clearing begun in the 17th century following European settlement had slowed by the late 19th century. Through the later part of the 20th century many areas of previously forested land in the United States were allowed to revert to forests or were actively reforested. The impacts of these land-use changes still influence C fluxes from these forest lands. More recently, the 1970s and 1980s saw a resurgence of federally-sponsored forest management programs (e.g., the Forestry Incentive Program) and soil conservation programs (e.g., the Conservation Reserve Program), which have focused on tree planting, improving timber management activities, combating soil erosion, and converting marginal cropland to forests. In addition to forest regeneration and management, forest

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[176] The term "biomass density" refers to the mass of live vegetation per unit area. It is usually measured on a dry-weight basis. Dry biomass is 50 percent C by weight.

harvests have also affected net C fluxes. Because most of the timber harvested from U.S. forests is used in wood products, and many discarded wood products are disposed of in SWDS rather than by incineration, significant quantities of C in harvested wood are transferred to long-term storage pools rather than being released rapidly to the atmosphere (Skog and Nicholson 1998, Skog 2008). The size of these long-term C storage pools has increased during the last century.

Changes in C stocks in U.S. forests and harvested wood were estimated to account for net sequestration of 863 Tg CO_2 Eq. (235 Tg C) in 2009 (Table 7-6, Table 7-7, and Table 7-8). In addition to the net accumulation of C in harvested wood pools, sequestration is a reflection of net forest growth and increasing forest area over this period. Overall, average C in forest ecosystem biomass (aboveground and belowground) increased from 67 to 73 Mg C/ha between 1990 and 2010 (see Annex 3-12 for average C densities by specific regions and forest types). Continuous, regular annual surveys are not available over the period for each state; therefore, estimates for non-survey years were derived by interpolation between known data points. Survey years vary from state to state, and national estimates are a composite of individual state surveys. Therefore, changes in sequestration over the interval 1990 to 2009 are the result of the sequences of new inventories for each state. C in forest ecosystem biomass had the greatest effect on total change through increases in C density and total forest land. Management practices that increase C stocks on forest land, as well as afforestation and reforestation efforts, influence the trends of increased C densities in forests and increased forest land in the United States.

The decline in net additions to HWP carbon stocks continued though 2009 from the recent high point in 2006. This is due to sharp declines in U.S. production of solidwood and paper products in 2009 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2009 was exceeded by discards from uses. The result is a net reduction in the amount of HWP carbon that is held in products in use during 2009. For 2009, additions to landfills still exceeded emissions from landfills and the net additions to landfills have remained relatively stable. Overall, there were net carbon additions to HWP in use and in landfills combined in 2009.

Table 7-6: Net Annual Changes in C Stocks (Tg CO_2/yr) in Forest and Harvested Wood Pools

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest	**(549.3)**	**(265.4)**	**(806.1)**	**(808.9)**	**(808.9)**	**(808.9)**	**(808.9)**
Aboveground Biomass	(360.0)	(287.0)	(447.9)	(447.9)	(447.9)	(447.9)	(447.9)
Belowground Biomass	(70.9)	(57.5)	(88.4)	(88.4)	(88.4)	(88.4)	(88.4)
Dead Wood	(31.6)	(12.9)	(30.8)	(33.5)	(33.5)	(33.5)	(33.5)
Litter	(32.2)	27.5	(41.9)	(41.9)	(41.9)	(41.9)	(41.9)
Soil Organic Carbon	(54.7)	64.6	(197.2)	(197.2)	(197.2)	(197.2)	(197.2)
Harvested Wood	**(131.8)**	**(112.9)**	**(105.4)**	**(108.6)**	**(103.0)**	**(82.1)**	**(54.3)**
Products in Use	(64.8)	(47.0)	(45.4)	(45.1)	(39.1)	(19.1)	6.8
SWDS	(67.0)	(65.9)	(59.9)	(63.4)	(63.8)	(63.0)	(61.1)
Total Net Flux	**(681.1)**	**(378.3)**	**(911.5)**	**(917.5)**	**(911.9)**	**(891.0)**	**(863.1)**

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed forests in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Forest area estimates are based on interpolation and extrapolation of inventory data as described in the text and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Table 7-7: Net Annual Changes in C Stocks (Tg C/yr) in Forest and Harvested Wood Pools

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Forest	**(149.8)**	**(72.4)**	**(219.9)**	**(220.6)**	**(220.6)**	**(220.6)**	**(220.6)**
Aboveground Biomass	(98.2)	(78.3)	(122.1)	(122.1)	(122.1)	(122.1)	(122.1)
Belowground Biomass	(19.3)	(15.7)	(24.1)	(24.1)	(24.1)	(24.1)	(24.1)
Dead Wood	(8.6)	(3.5)	(8.4)	(9.1)	(9.1)	(9.1)	(9.1)

Litter	(8.8)		7.5		(11.4)	(11.4)	(11.4)	(11.4)	(11.4)
Soil Organic C	(14.9)		17.6		(53.8)	(53.8)	(53.8)	(53.8)	(53.8)
Harvested Wood	**(35.9)**		**(30.8)**		**(28.7)**	**(29.6)**	**(28.1)**	**(22.4)**	**(14.8)**
Products in Use	(17.7)		(12.8)		(12.4)	(12.3)	(10.7)	(5.2)	1.9
SWDS	(18.3)		(18.0)		(16.3)	(17.3)	(17.4)	(17.2)	(16.7)
Total Net Flux	**(185.7)**		**(103.2)**		**(248.6)**	**(250.2)**	**(248.7)**	**(243.0)**	**(235.4)**

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed lands in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Stock estimates for forest and harvested wood C storage pools are presented in Table 7-8. Together, the aboveground live and forest soil pools account for a large proportion of total forest C stocks. C stocks in all non-soil pools increased over time. Therefore, C sequestration was greater than C emissions from forests, as discussed above. Figure 7-4 shows county-average C densities for live trees on forest land, including both above- and belowground biomass.

Table 7-8: Forest area (1000 ha) and C Stocks (Tg C) in Forest and Harvested Wood Pools

	1990		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Forest Area (1000 ha)	**269,137**		**274,183**		**276,769**	**277,561**	**278,354**	**279,147**	**279,939**	**280,732**
Carbon Pools (Tg C)										
Forest	**42,783**		**44,108**		**44,886**	**45,105**	**45,326**	**45,547**	**45,767**	**45,988**
Aboveground Biomass	15,072		16,024		16,536	16,658	16,780	16,902	17,024	17,147
Belowground Biomass	2,995		3,183		3,285	3,309	3,333	3,357	3,381	3,405
Dead Wood	2,960		3,031		3,060	3,068	3,077	3,086	3,096	3,105
Litter	4,791		4,845		4,862	4,873	4,885	4,896	4,908	4,919
Soil Organic C	16,96		17,025		17,143	17,197	17,251	17,304	17,358	17,412
Harvested Wood	**1,859**		**2,187**		**2,325**	**2,354**	**2,383**	**2,412**	**2,434**	**2,449**
Products in Use	1,231		1,382		1,436	1,448	1,460	1,471	1,476	1,474
SWDS	628		805		890	906	923	941	958	974
Total C Stock	**44,643**		**46,296**		**47,211**	**47,459**	**47,710**	**47,958**	**48,201**	**48,437**

Note: Forest area estimates include portions of managed forests in Alaska for which survey data are available. Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a large portion of Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Wood product stocks include exports, even if the logs are processed in other countries, and exclude imports. Forest area estimates are based on interpolation and extrapolation of inventory data as described in Smith et al. (2010) and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding. Inventories are assumed to represent stocks as of January 1 of the inventory year. Flux is the net annual change in stock. Thus, an estimate of flux for 2006 requires estimates of C stocks for 2006 and 2007.

Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4: Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

[BEGIN BOX]

Box 7-2: CO_2 Emissions from Forest Fires

As stated previously, the forest inventory approach implicitly accounts for emissions due to disturbances such as forest fires, because only C remaining in the forest is estimated. Net C stock change is estimated by subtracting consecutive C stock estimates. A disturbance removes C from the forest. The inventory data on which net C stock estimates are based already reflect this C loss. Therefore, estimates of net annual changes in C stocks for U.S. forestland already account for CO_2 emissions from forest fires occurring in the lower 48 states as well as in the proportion of Alaska's managed forest land captured in this inventory. Because it is of interest to quantify the magnitude of CO_2 emissions from fire disturbance, these estimates are being highlighted here, using the full extent of available data. Non-CO_2 greenhouse gas emissions from forest fires are also quantified in a separate section below.

The IPCC (2003) methodology and IPCC (2006) default combustion factor for wildfire were employed to estimate CO_2 emissions from forest fires. CO_2 emissions for wildfires and prescribed fires in the lower 48 states and wildfires in Alaska in 2009 were estimated to be 124.3 Tg CO_2/yr. This amount is masked in the estimate of net annual forest carbon stock change for 2009, however, because this net estimate accounts for the amount sequestered minus any emissions.

Table 7-9: Estimates of CO_2 (Tg/yr) emissions for the lower 48 states and Alaska[1]

Year	CO_2 emitted from Wildfires in Lower 48 States (Tg/yr)	CO_2 emitted from Prescribed Fires in Lower 48 States (Tg/yr)	CO_2 emitted from Wildfires in Alaska (Tg/yr)	Total CO_2 emitted (Tg/yr)
1990	42.1	8.5	+	50.7
2000	225.1	2.1	+	227.3
2005	131.0	24.8	+	155.9
2006	313.6	29.3	+	342.9
2007	284.1	34.0	+	318.1
2008	169.0	20.8	+	189.8
2009	97.1	27.3	+	124.3

+ Does not exceed 0.05 Tg CO_2 Eq.

[1] Note that these emissions have already been accounted for in the estimates of net annual changes in C stocks, which account for the amount sequestered minus any emissions.

[END BOX]

Methodology and Data Sources

The methodology described herein is consistent with IPCC (2003, 2006) and IPCC/UNEP/OECD/IEA (1997). Forest ecosystem C stocks and net annual C stock change are determined according to stock-difference methods, which involve applying C estimation factors to forest inventory data and interpolating between successive inventory-based estimates of C stocks. Harvested wood C estimates are based on factors such as the allocation of wood to various primary and end-use products as well as half-life (the time at which half of amount placed in use will have been discarded from use) and expected disposition (e.g., product pool, SWDS, combustion). An overview of the different methodologies and data sources used to estimate the C in forest ecosystems or harvested wood products is provided here. See Annex 3.12 for details and additional information related to the methods and data.

Forest Ecosystem Carbon from Forest Inventory

Forest ecosystem stock and flux estimates are based on the stock-difference method and calculations for all estimates are in units of C. Separate estimates are made for the five IPCC C storage pools described above. All estimates are based on data collected from the extensive array of permanent forest inventory plots in the United States as well as models employed to fill gaps in field data. Carbon conversion factors are applied at the disaggregated level of each inventory plot and then appropriately expanded to population estimates. A combination of tiers as outlined by IPCC (2006) is used. The Tier 3 biomass C values are from forest inventory tree-level data. The Tier 2 dead organic and soil C pools are based on empirical or process models from the inventory data. All carbon conversion factors are specific to regions or individual states within the U.S., which are further classified according to characteristic forest types within each region.

The first step in developing forest ecosystem estimates is to identify useful inventory data and resolve any inconsistencies among datasets. Forest inventory data were obtained from the USDA Forest Service FIA program (Frayer and Furnival 1999, USDA Forest Service 2010b). Inventories include data collected on permanent inventory plots on forest lands[177] and are organized as a number of separate datasets, each representing a complete inventory, or survey, of an individual state at a specified time. Some of the more recent annual inventories reported for some states include "moving window" averages, which means that a portion—but not all—of the previous year's inventory is updated each year (USDA Forest Service 2010d). Forest C calculations are organized according to these state surveys, and the frequency of surveys varies by state. All available data sets are identified for each state starting with pre-1990 data, and all unique surveys are identified for stock and change calculations. Since C stock change is based on differences between successive surveys within each state, accurate estimates of net C flux thus depend on consistent representation of forest land between these successive inventories. In order to achieve this consistency from 1990 to the present, states are sometimes subdivided into sub-state areas where the sum of sub-state inventories produces the best whole-state representation of C change as discussed in Smith et al. (2010).

The principal FIA datasets employed are freely available for download at USDA Forest Service (2010b) as the Forest Inventory and Analysis Database (FIADB) Version 4.0. However, to achieve consistent representation (spatial and temporal), two other general sources of past FIA data are included as necessary. First, older FIA plot- and tree-level data—not in the current FIADB format—are used if available. Second, Resources Planning Act Assessment (RPA) databases, which are periodic, plot-level only, summaries of state inventories, are used mostly to provide the data at or before 1990. An additional forest inventory data source is the Integrated Database (IDB), which is a compilation of periodic forest inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). These data were identified by Heath et al. (submitted) as the most appropriate non-FIADB sources for these states and are included in this inventory. See USDA Forest Service (2010a) for information on current and older data as well as additional FIA Program features. A detailed list of the specific forest inventory data used in this inventory is in Annex 3.12.

Forest C stocks are estimated from inventory data by a collection of conversion factors and models (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004, Smith et al. 2006), which have been formalized in an FIADB-to-carbon calculator (Smith et al. 2010). The conversion factors and model coefficients are categorized by region and forest type, and forest C stock estimates are calculated from application of these factors at the scale of FIA inventory plots. The results are estimates of C density (Mg C per hectare) for six forest ecosystem pools: live trees, standing dead trees, understory vegetation, down dead wood, forest floor, and soil organic matter. The six carbon pools used in the FIADB-to-carbon calculator are aggregated to the 5 carbon pools defined by IPCC (2006): aboveground biomass, belowground biomass, dead wood, litter, and soil organic matter. All non-soil pools except forest floor are separated into aboveground and belowground components. The live tree and understory C pools are pooled as biomass, and standing dead trees and down dead wood are pooled as dead wood, in accordance with IPCC (2006).

Once plot-level C stocks are calculated as C densities on *Forest Land Remaining Forest Land* for the five IPCC (2006) reporting pools, the stocks are expanded to population estimates according to methods appropriate to the respective inventory data (for example, see Bechtold and Patterson (2005)). These expanded C stock estimates are summed to state or sub-state total C stocks. Annualized estimates of C stocks are developed by using available FIA inventory data and interpolating or extrapolating to assign a C stock to each year in the 1990 through2010 time series. Flux, or net annual stock change, is estimated by calculating the difference between two successive years and applying the appropriate sign convention; net increases in ecosystem C are identified as negative flux. By convention, inventories are assigned to represent stocks as of January 1 of the inventory year; an estimate of flux for 1996 requires estimates of C stocks for 1996 and 1997, for example. Additional discussion of the use of FIA inventory data and the C conversion process is in Annex 3.12.

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[177] Forest land in the United States includes land that is at least 10 percent stocked with trees of any size. Timberland is the most productive type of forest land, which is on unreserved land and is producing or capable of producing crops of industrial wood.

Carbon in Biomass

Live tree C pools include aboveground and belowground (coarse root) biomass of live trees with diameter at diameter breast height (d.b.h.) of at least 2.54 cm at 1.37 m above the forest floor. Separate estimates are made for full-tree and aboveground-only biomass in order to estimate the belowground component. If inventory plots include data on individual trees, tree C is based on Jenkins et al. (2003) and is a function of species and diameter. Some inventory data do not provide measurements of individual trees; tree C in these plots is estimated from plot-level volume of merchantable wood, or growing-stock volume, of live trees, which is calculated from updates of Smith et al. (2003). These biomass conversion and expansion factors (BCEFs) are applied to about 3 percent of the inventory records, all of which are pre-1998 data. Some inventory data, particularly some of the older datasets, may not include sufficient information to calculate tree C because of incomplete or missing tree or volume data; C estimates for these plots are based on averages from similar, but more complete, inventory data. This applies to an additional 2 percent of inventory records, which represent older (pre-1998) non-timberlands.

Understory vegetation is a minor component of biomass, which is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than 2.54 cm d.b.h. In the current inventory, it is assumed that 10 percent of total understory C mass is belowground. Estimates of C density are based on information in Birdsey (1996). Understory frequently represents over 1 percent of C in biomass, but its contribution rarely exceeds 2 percent of the total.

Carbon in Dead Organic Matter

Dead organic matter is initially calculated as three separate pools with C stocks modeled from inventory data. Estimates are specific to regions and forest types within each region, and stratification of forest land for dead organic matter calculations is identical to that used for biomass through the state and sub-state use of FIA data as discussed above. The two components of dead wood—standing dead trees and down dead wood—are estimated separately. The standing dead tree C pools include aboveground and belowground (coarse root) mass and include trees of at least 2.54 cm d.b.h. Calculations are BCEF-like factors based on updates of Smith et al. (2003). Down dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. Down dead wood includes stumps and roots of harvested trees. Ratios of down dead wood to live tree are used to estimate this quantity. Litter C is the pool of organic C (also known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. Estimates are based on equations of Smith and Heath (2002).

Carbon in Forest Soil

Soil organic C (SOC) includes all organic material in soil to a depth of 1 meter but excludes the coarse roots of the biomass or dead wood pools. Estimates of SOC are based on the national STATSGO spatial database (USDA 1991), which includes region and soil type information. SOC determination is based on the general approach described by Amichev and Galbraith (2004). Links to FIA inventory data were developed with the assistance of the USDA Forest Service FIA Geospatial Service Center by overlaying FIA forest inventory plots on the soil C map. This method produced mean SOC densities stratified by region and forest type group. It did not provide separate estimates for mineral or organic soils but instead weighted their contribution to the overall average based on the relative amount of each within forest land. Thus, forest SOC is a function of species and location, and net change also depends on these two factors as total forest area changes. In this respect, SOC provides a country-specific reference stock for 1990-present, but it does not reflect effects of past land use.

Harvested Wood Carbon

Estimates of the HWP contribution to forest C sinks and emissions (hereafter called "HWP Contribution") are based on methods described in Skog (2008) using the WOODCARB II model. These methods are based on IPCC (2006) guidance for estimating HWP C. IPCC (2006) provides methods that allow Parties to report HWP Contribution using one of several different accounting approaches: production, stock change and atmospheric flow, as well as a default method that assumes there is no change in HWP C stocks (see Annex 3.12 for more details about each approach). The United States uses the production accounting approach to report HWP Contribution. Under the production approach, C in exported wood is estimated as if it remains in the United States, and C in imported wood is not included in inventory estimates. Though reported U.S. HWP estimates are based on the production approach, estimates resulting from use of the two alternative approaches, the stock change and atmospheric flow approaches, are also presented for comparison (see Annex 3.12). Annual estimates of change are calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in solid waste disposal sites (SWDS).

Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end-uses. There is one product category and one end-use category for paper. Additions to and removals from pools are tracked beginning in 1900, with the exception that additions of softwood lumber to housing begins in 1800. Solidwood and paper product production and trade data are from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census; 1976; Ulrich, 1985, 1989; Steer 1948; AF&PA 2006a 2006b; Howard 2003, 2007). Estimates for disposal of products reflect the change over time in the fraction of products discarded to SWDS (as opposed to burning or recycling) and the fraction of SWDS that are in sanitary landfills versus dumps.

There are five annual HWP variables that are used in varying combinations to estimate HWP Contribution using any one of the three main approaches listed above. These are:

(1A) annual change of C in wood and paper products in use in the United States,

(1B) annual change of C in wood and paper products in SWDS in the United States,

(2A) annual change of C in wood and paper products in use in the United States and other countries where the wood came from trees harvested in the United States,

(2B) annual change of C in wood and paper products in SWDS in the United States and other countries where the wood came from trees harvested in the United States,

(3) C in imports of wood, pulp, and paper to the United States,

(4) C in exports of wood, pulp and paper from the United States, and

(5) C in annual harvest of wood from forests in the United States.

The sum of variables 2A and 2B yields the estimate for HWP Contribution under the production accounting approach. A key assumption for estimating these variables is that products exported from the United States and held in pools in other countries have the same half lives for products in use, the same percentage of discarded products going to SWDS, and the same decay rates in SWDS as they would in the United States.

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis placed bounds on current flux for forest ecosystems as well as C in harvested wood products through Monte Carlo simulation of the Methods described above and probabilistic sampling of C conversion factors and inventory data. See Annex 3.12 for additional information. The 2009 flux estimate for forest C stocks is estimated to be between -1,014 and -714 Tg CO_2 Eq. at a 95 percent confidence level. This includes a range of -662 to -959 Tg CO_2 Eq. in forest ecosystems and -69 to -41 Tg CO_2 Eq. for HWP.

Table 7-10: Tier 2 Quantitative Uncertainty Estimates for Net CO_2 Flux from Forest Land Remaining Forest Land: Changes in Forest C Stocks (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate[a]**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Forest Ecosystem	CO_2	(808.9)	(959.4)	(661.7)	-19%	-18%
Harvested Wood Products	CO_2	(54.3)	(68.6)	(41.0)	-27%	-24%
Total Forest	**CO_2**	**(863.1)**	**(1,014.4)**	**(713.9)**	**-18%**	**-17%**

Note: Parentheses indicate negative values or net sequestration.

[a]Range of flux estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

As discussed above, the FIA program has conducted consistent forest surveys based on extensive statistically-based sampling of most of the forest land in the conterminous United States, dating back to 1952. The main purpose of the FIA program has been to estimate areas, volume of growing stock, and timber products output and utilization factors. The FIA program includes numerous quality assurance and quality control (QA/QC) procedures, including calibration among field crews, duplicate surveys of some plots, and systematic checking of recorded data. Because of the statistically-based sampling, the large number of survey plots, and the quality of the data, the survey databases developed by the FIA program form a strong foundation for C stock estimates. Field sampling protocols, summary data, and detailed inventory databases are archived and are publicly available on the Internet (USDA Forest Service 2010d).

Many key calculations for estimating current forest C stocks based on FIA data were developed to fill data gaps in assessing forest carbon and have been in use for many years to produce national assessments of forest C stocks and stock changes (see additional discussion and citations in the Methodology section above and in Annex 3.12). General quality control procedures were used in performing calculations to estimate C stocks based on survey data. For example, the derived C datasets, which include inventory variables such as areas and volumes, were compared to standard inventory summaries such as the forest resource statistics of Smith et al. (2009) or selected population estimates generated from FIADB 4.0, which are available at an FIA internet site (USDA Forest Service 2009b). Agreement between the C datasets and the original inventories is important to verify accuracy of the data used. Finally, C stock estimates were compared with previous inventory report estimates to ensure that any differences could be explained by either new data or revised calculation methods (see the “Recalculations” discussion, below).

Estimates of the HWP variables and the HWP contribution under the production accounting approach use data from U.S. Census and USDA Forest Service surveys of production and trade. Factors to convert wood and paper to units C are based on estimates by industry and Forest Service published sources. The WOODCARB II model uses estimation methods suggested by IPCC (2006). Estimates of annual C change in solidwood and paper products in use were calibrated to meet two independent criteria. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needs to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. Meeting the first criterion resulted in an estimated half life of about 80 years for single family housing built in the 1920s, which is confirmed by other U.S. Census data on housing. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needs to match EPA estimates of discards each year over the period 1990 to 2000 (EPA 2006). These criteria help reduce uncertainty in estimates of annual change in C in products in use in the United States and, to a lesser degree, reduce uncertainty in estimates of annual change in C in products made from wood harvested in the United States. In addition, WOODCARB II landfill decay rates have been validated by ensuring that estimates of CH_4 emissions from landfills based on EPA (2006) data are reasonable in comparison with CH_4 estimates based on WOODCARB II landfill decay rates.

Recalculations Discussion

The basic models used to estimate forest ecosystem and HWP C stocks and change are unchanged from the previous Inventory (Smith et al. 2010, Skog 2008). Many of the state-level estimates for 1990 through the present are relatively similar to the values previously reported (EPA 2010). Recent forest inventory additions to the FIADB include newer annual inventory data for most states including Oklahoma, which had the effect of increasing overall net sequestration estimated for the interval from 2000 through 2008. An additional change to the FIADB was the addition of some older periodic inventories for some southern states; these were incorporated into the calculations but did not appreciably affect national trends. The addition of the IDB forest inventories for a part of the series for California, Oregon, and Washington did affect recalculations for those states and the United States as a whole; it tended to decrease net sequestration throughout the 1990 to 2008 interval. However, the decreased sequestration associated with the use of the IDB was offset by the increased sequestration associated with newer annual inventory data for the post-2000 interval.

Planned Improvements

The ongoing annual surveys by the FIA Program will improve precision of forest C estimates as new state surveys become available (USDA Forest Service 2010b), particularly in western states. The annual surveys will eventually include all states. To date, three states are not yet reporting any data from the annualized sampling design of FIA: Hawaii, New Mexico and Wyoming. Estimates for these states are currently based on older, periodic data. Hawaii and U.S. territories will also be included when appropriate forest C data are available. In addition, the more intensive sampling of down dead wood, litter, and soil organic C on some of the permanent FIA plots continues and will substantially improve resolution of C pools at the plot level for all U.S. forest land as this information becomes available (Woodall et al. in press). Improved resolution, incorporating more of Alaska's forests, and using annualized sampling data as it becomes available for those states currently not reporting are planned for future reporting.

As more information becomes available about historical land use, the ongoing effects of changes in land use and forest management will be better accounted for in estimates of soil C (Birdsey and Lewis 2003, Woodbury et al. 2006, Woodbury et al. 2007). Currently, soil C estimates are based on the assumption that soil C density depends only on broad forest type group, not on land-use history, but long-term residual effects on soil and forest floor C stocks are likely after land-use change. Estimates of such effects depend on identifying past land use changes associated with forest lands.

Similarly, agroforestry practices, such as windbreaks or riparian forest buffers along waterways, are not currently accounted for in the inventory. In order to properly account for the C stocks and fluxes associated with agroforestry, research will be needed that provides the basis and tools for including these plantings in a nation-wide inventory, as well as the means for entity-level reporting.

Non-CO_2 Emissions from Forest Fires

Emissions of non-CO_2 gases from forest fires were estimated using the default IPCC (2003) methodology incorporating default IPCC (2006) emissions factors and combustion factor for wildfires. Emissions from this source in 2009 were estimated to be 7.8 Tg CO_2 Eq**.** of CH_4 and 6.4 Tg CO_2 Eq. of N_2O, as shown in Table 7-11 and Table 7-12. The estimates of non-CO_2 emissions from forest fires account for wildfires in the lower 48 states and Alaska as well as prescribed fires in the lower 48 states.

Table 7-11: Estimated Non-CO_2 Emissions from Forest Fires (Tg CO_2 Eq.) for U.S. Forests[1]

Gas	1990		2000		2005	2006	2007	2008	2009
CH_4	3.2		14.3		9.8	21.6	20.0	11.9	7.8
N_2O	2.6		11.7		8.0	17.6	16.3	9.8	6.4
Total	**5.8**		**26.0**		**17.8**	**39.2**	**36.3**	**21.7**	**14.2**

[1] Calculated based on C emission estimates in *Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Table 7-12: Estimated Non-CO_2 Emissions from Forest Fires (Gg Gas) for U.S. Forests[1]

Gas	1990		2000		2005	2006	2007	2008	2009
CH_4	152		682		467	1,027	953	569	372
N_2O	8		38		26	57	53	31	21

[1] Calculated based on C emission estimates *in Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Methodology

The IPCC (2003) Tier 2 default methodology was used to calculate non-CO_2 emissions from forest fires. However, more up-to-date default emission factors from IPCC (2006) were converted into gas-specific emission ratios and incorporated into the methodology**.** Estimates of CH_4 and N_2O emissions were calculated by multiplying the total estimated CO_2 emitted from forest burned by the gas-specific emissions ratios. CO_2 emissions were estimated by multiplying total C emitted (Table 7-13) by the C to CO_2 conversion factor of 44/12 and by 92.8 percent, which is the estimated proportion of C emitted as CO_2 (Smith 2008a). The equations used were:

$$CH_4 \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (CH_4 \text{ to } CO_2 \text{ emission ratio})$$

$$N_2O \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (N_2O \text{ to } CO_2 \text{ emission ratio})$$

Estimates for C emitted from forest fires are the same estimates used to generate estimates of CO_2 presented earlier in Box 7-1. Estimates for C emitted include emissions from wildfires in both Alaska and the lower 48 states as well as emissions from prescribed fires in the lower 48 states only (based on expert judgment that prescribed fires only occur in the lower 48 states) (Smith 2008a). The IPCC (2006) default combustion factor of 0.45 for “all ‘other’ temperate forests” was applied in estimating C emitted from both wildfires and prescribed fires. See the explanation in Annex 3.12 for more details on the methodology used to estimate C emitted from forest fires.

Table 7-13: Estimated Carbon Released from Forest Fires for U.S. Forests

Year	C Emitted (Tg/yr)
1990	14.9
2000	66.8
2005	45.8
2006	100.8
2007	93.5
2008	55.8
2009	36.5

Uncertainty and Time-Series Consistency

Non-CO_2 gases emitted from forest fires depend on several variables, including: forest area for Alaska and the lower 48 states; average C densities for wildfires in Alaska, wildfires in the lower 48 states, and prescribed fires in the lower 48 states; emission ratios; and combustion factor values (proportion of biomass consumed by fire). To quantify the uncertainties for emissions from forest fires, a Monte Carlo (Tier 2) uncertainty analysis was performed using information about the uncertainty surrounding each of these variables. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-14.

Table 7-14: Tier 2 Quantitative Uncertainty Estimates of Non-CO_2 Emissions from Forest Fires in Forest Land Remaining Forest Land (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Non-CO_2 Emissions from Forest Fires	CH_4	7.8	2.2	19.2	-72%	+145%
Non-CO_2 Emissions from Forest Fires	N_2O	6.4	1.8	15.7	-72%	+145%

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for forest fires included checking input data, documentation, and calculations to ensure data were properly handled through the inventory process. Errors that were found during this process were corrected as necessary.

Recalculations Discussion

This is the second year in which non-CO_2 emissions were calculated using the 2006 IPCC default emission factors for CH_4 and N_2O instead of the 2003 IPCC default emission factors. These default emission factors were converted to CH_4 to CO_2 and N_2O to CO_2 emission ratios and then multiplied by CO_2 emissions to estimate CH_4 and N_2O emissions. The previous 2003 IPCC methodology provides emission ratios that are multiplied by total carbon emitted.

Planned Improvements

The default combustion factor of 0.45 from IPCC (2006) was applied in estimating C emitted from both wildfires and prescribed fires. Additional research into the availability of a combustion factor specific to prescribed fires is being conducted.

Direct N_2O Fluxes from Forest Soils (IPCC Source Category 5A1)

Of the synthetic N fertilizers applied to soils in the United States, no more than one percent is applied to forest soils. Application rates are similar to those occurring on cropped soils, but in any given year, only a small proportion of total forested land receives N fertilizer. This is because forests are typically fertilized only twice during their approximately 40-year growth cycle (once at planting and once approximately 20 years later). Thus, while the rate of N fertilizer application for the area of forests that receives N fertilizer in any given year is relatively high, the average annual application is quite low as inferred by dividing all forest land that may undergo N fertilization at some point during its growing cycle by the amount of N fertilizer added to these forests in a given year. Direct N_2O emissions from forest soils in 2009 were 0.4 Tg CO_2 Eq. (1 Gg). Emissions have increased by 455 percent from 1990 to 2009 as a result of an increase in the area of N fertilized pine plantations in the southeastern United States and Douglas-fir timberland in western Washington and Oregon. Total forest soil N_2O emissions are summarized in Table 7-15.

Table 7-15: Direct N_2O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO_2 Eq. and Gg N_2O)

Year	Tg CO_2 Eq.	Gg
1990	0.1	0.2
2000	0.4	1.3
2005	0.4	1.2
2006	0.4	1.2
2007	0.4	1.2
2008	0.4	1.2
2009	0.4	1.2

Note: These estimates include direct N_2O emissions from N fertilizer additions only. Indirect N_2O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Forest Land Remaining Forest Land* and from *Land Converted to Forest Land*.

Methodology

The IPCC Tier 1 approach was used to estimate N_2O from soils within *Forest Land Remaining Forest Land*. According to U.S. Forest Service statistics for 1996 (USDA Forest Service 2001), approximately 75 percent of trees planted were for timber, and about 60 percent of national total harvested forest area is in the southeastern United States. Although southeastern pine plantations represent the majority of fertilized forests in the United States, this Inventory also accounted for N fertilizer application to commercial Douglas-fir stands in western Oregon and Washington. For the Southeast, estimates of direct N_2O emissions from fertilizer applications to forests were based on the area of pine plantations receiving fertilizer in the southeastern United States and estimated application rates (Albaugh et al. 2007). Not accounting for fertilizer applied to non-pine plantations is justified because fertilization is routine for pine forests but rare for hardwoods (Binkley et al. 1995). For each year, the area of pine receiving N fertilizer was multiplied by the weighted average of the reported range of N fertilization rates (121 lbs. N per acre). Area data for pine plantations receiving fertilizer in the Southeast were not available for 2005, 2006, 2007 and 2008, so data from 2004 were used for these years. For commercial forests in Oregon and Washington, only fertilizer applied to Douglas-fir was accounted for, because the vast majority (~95 percent) of the total fertilizer applied to forests in this region is applied to Douglas-fir (Briggs 2007). Estimates of total Douglas-fir area and the portion of fertilized area were multiplied to obtain annual area estimates of fertilized Douglas-fir stands. The annual area estimates were multiplied by the typical rate used in this region (200 lbs. N per acre) to estimate total N applied (Briggs 2007), and the total N applied to forests was multiplied by the IPCC (2006) default emission factor of 1 percent to estimate direct N_2O emissions. The volatilization and leaching/runoff N fractions for forest land, calculated according to the IPCC default factors of 10 percent and 30 percent, respectively, were included with the indirect emissions in the Agricultural Soil Management source category (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N_2O emitted from forests depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and tree planting/harvesting cycles. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. IPCC (2006) does not incorporate any of these variables into the default methodology, except variation in estimated fertilizer application rates and estimated areas of forested land receiving N fertilizer. All forest soils are treated equivalently under this methodology. Furthermore, only synthetic N fertilizers are captured, so applications of organic N fertilizers are not estimated. However, the total quantity of organic N inputs to soils is included in the Agricultural Soil Management and *Settlements Remaining Settlements* sections.

Uncertainties exist in the fertilization rates, annual area of forest lands receiving fertilizer, and the emission factors. Fertilization rates were assigned a default level[178] of uncertainty at ±50 percent, and area receiving fertilizer was assigned a ±20 percent according to expert knowledge (Binkley 2004). IPCC (2006) provided estimates for the uncertainty associated with direct N_2O emission factor for synthetic N fertilizer application to soils. Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emissions estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-16. N_2O fluxes from soils were estimated to be between 0.1 and 1.1 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 59 percent below and 211 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 7-16: Quantitative Uncertainty Estimates of N_2O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Forest Land Remaining Forest Land: N_2O Fluxes from Soils	N_2O	0.4	0.1	1.1	-59%	+211%

Note: This estimate includes direct N_2O emissions from N fertilizer additions to both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

Planned Improvements

State-level area data will be acquired for southeastern pine plantations and northwestern Douglas-fir forests receiving fertilizer to estimate soil N_2O emission by state and provide information about regional variation in emission patterns.

7.3. Land Converted to Forest Land (IPCC Source Category 5A2)

Land-use change is constantly occurring, and areas under a number of differing land-use types are converted to forest each year, just as forest land is converted to other uses. However, the magnitude of these changes is not currently known. Given the paucity of available land-use information relevant to this particular IPCC source category, it is not possible to separate CO_2 or N_2O fluxes on *Land Converted to Forest Land* from fluxes on *Forest Land Remaining Forest Land* at this time.

7.4. Cropland Remaining Cropland (IPCC Source Category 5B1)

Mineral and Organic Soil Carbon Stock Changes

Soils contain both organic and inorganic forms of C, but soil organic C (SOC) stocks are the main source and sink for atmospheric CO_2 in most soils. Changes in inorganic C stocks are typically minor. In addition, soil organic C is

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[178] Uncertainty is unknown for the fertilization rates so a conservative value of ±50% was used in the analysis.

the dominant organic C pool in cropland ecosystems, because biomass and dead organic matter have considerably less C and those pools are relatively ephemeral. IPCC (2006) recommends reporting changes in soil organic C stocks due to agricultural land-use and management activities on mineral and organic soils.[179]

Typical well-drained mineral soils contain from 1 to 6 percent organic C by weight, although mineral soils that are saturated with water for substantial periods during the year may contain significantly more C (NRCS 1999). Conversion of mineral soils from their native state to agricultural uses can cause as much as half of the SOC to be decomposed and the C lost to the atmosphere. The rate and ultimate magnitude of C loss will depend on pre-conversion conditions, conversion method and subsequent management practices, climate, and soil type. In the tropics, 40 to 60 percent of the C loss generally occurs within the first 10 years following conversion; C stocks continue to decline in subsequent decades but at a much slower rate. In temperate regions, C loss can continue for several decades, reducing stocks by 20 to 40 percent of native C levels. Eventually, the soil can reach a new equilibrium that reflects a balance between C inputs (e.g., decayed plant matter, roots, and organic amendments such as manure and crop residues) and C loss through microbial decomposition of organic matter. However, land use, management, and other conditions may change before the new equilibrium is reached. The quantity and quality of organic matter inputs and their rate of decomposition are determined by the combined interaction of climate, soil properties, and land use. Land use and agricultural practices such as clearing, drainage, tillage, planting, grazing, crop residue management, fertilization, and flooding can modify both organic matter inputs and decomposition, and thereby result in a net flux of C to or from the pool of soil C.

Organic soils, also referred to as histosols, include all soils with more than 12 to 20 percent organic C by weight, depending on clay content (NRCS 1999, Brady and Weil 1999). The organic layer of these soils can be very deep (i.e., several meters), forming under inundated conditions in which minimal decomposition of plant residue occurs. When organic soils are prepared for crop production, they are drained and tilled, leading to aeration of the soil, which accelerates the rate of decomposition and CO_2 emissions. Because of the depth and richness of the organic layers, C loss from drained organic soils can continue over long periods of time. The rate of CO_2 emissions varies depending on climate and composition (i.e., decomposability) of the organic matter. Also, the use of organic soils for annual crop production leads to higher C loss rates than drainage of organic soils in grassland or forests, due to deeper drainage and more intensive management practices in cropland (Armentano and Verhoeven 1990, as cited in IPCC/UNEP/OECD/IEA 1997). Carbon losses are estimated from drained organic soils under both grassland and cropland management in this Inventory.

Cropland Remaining Cropland includes all cropland in an inventory year that had been cropland for the last 20 years[180] according to the USDA NRI land-use survey (USDA-NRCS 2000). The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Cropland Remaining Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include federal croplands in future C inventories.

The area of *Cropland Remaining Cropland* changes through time as land is converted to or from cropland management. CO_2 emissions and removals[181] due to changes in mineral soil C stocks are estimated using a Tier 3 approach for the majority of annual crops. A Tier 2 IPCC method is used for the remaining crops (vegetables, tobacco, perennial/horticultural crops, and rice) not included in the Tier 3 method. In addition, a Tier 2 method is used for very gravelly, cobbly, or shaley soils (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale) and for additional changes in mineral soil C stocks that were not addressed with the Tier 3 approach (i.e., change in C stocks after 2003 due to Conservation Reserve Program enrollment). Emissions from organic soils are estimated using a Tier 2 IPCC method.

Of the two sub-source categories, land-use and land management of mineral soils was the most important component of total net C stock change between 1990 and 2009 (see Table 7-17 and Table 7-18). In 2009, mineral soils were estimated to remove 45.1 Tg CO_2 Eq. (12.3 Tg C). This rate of C storage in mineral soils represented about a 20 percent decrease in the rate since the initial reporting year of 1990. Emissions from organic soils were

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[179] CO_2 emissions associated with liming are also estimated but are included in a separate section of the report.

[180] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[181] Note that removals occur through crop and forage uptake of CO_2 into biomass C that is later incorporated into soil pools.

27.7 Tg CO_2 Eq. (7.5 Tg C) in 2009. In total, U.S. agricultural soils in *Cropland Remaining Cropland* removed approximately 17.4 Tg CO_2 Eq. (4.7 Tg C) in 2009.

Table 7-17: Net CO_2 Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg CO_2 Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(56.8)	(57.9)	(45.9)	(46.8)	(47.3)	(45.7)	(45.1)
Organic Soils	27.4	27.7	27.7	27.7	27.7	27.7	27.7
Total Net Flux	**(29.4)**	**(30.2)**	**(18.3)**	**(19.1)**	**(19.7)**	**(18.1)**	**(17.4)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-18: Net CO_2 Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(15.5)	(15.8)	(12.5)	(12.8)	(12.9)	(12.5)	(12.3)
Organic Soils	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Total Net Flux	**(8.0)**	**(8.2)**	**(5.0)**	**(5.2)**	**(5.4)**	**(4.9)**	**(4.7)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The net reduction in soil C accumulation over the time series (39 percent from 1990 to 2009) was largely due to the declining influence of annual cropland enrolled in the Conservation Reserve Program, which began in the late 1980s. However, there were still positive increases in C stocks from land enrolled in the reserve program, as well as intensification of crop production by limiting the use of bare-summer fallow in semi-arid regions, increased hay production, and adoption of conservation tillage (i.e., reduced- and no-till practices).

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-5 and Figure 7-6. The highest rates of net C accumulation in mineral soils occurred in the Midwest, which is the area with the largest amounts of cropland managed with conservation tillage. Rates were also high in the Great Plains due to enrollment in the Conservation Reserve Program. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-5: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Figure 7-6: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Methodology

The following section includes a description of the methodology used to estimate changes in soil C stocks due to: (1) agricultural land-use and management activities on mineral soils; and (2) agricultural land-use and management activities on organic soils for *Cropland Remaining Cropland*.

Soil C stock changes were estimated for *Cropland Remaining Cropland* (as well as agricultural land falling into the IPCC categories *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*) according to land-use histories recorded in the USDA National Resources Inventory (NRI) survey (USDA-NRCS 2000). The NRI is a statistically-based sample of all non-federal land, and includes approximately 260,000 points in agricultural land for the conterminous United States and Hawaii.[182] Each point is associated with an “expansion factor” that allows scaling of C stock changes from NRI points to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some

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[182] NRI points were classified as agricultural if under grassland or cropland management between 1990 and 2003.

management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. For cropland, data were collected for 4 out of 5 years in the cycle (i.e., 1979-1982, 1984-1987, 1989-1992, and 1994-1997). However, the NRI program began collecting annual data in 1998, and data are currently available through 2003. NRI points were classified as *Cropland Remaining Cropland* in a given year between 1990 and 2009 if the land use had been cropland for 20 years.[183] Cropland includes all land used to produce food and fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for mineral soils used to produce a majority of annual crops in the United States (Ogle et al. 2010). The remaining crops on mineral soils were estimated using an IPCC Tier 2 method (Ogle et al. 2003), including vegetables, tobacco, perennial/horticultural crops, rice, and crops rotated with these crops. The Tier 2 method was also used for very gravelly, cobbly, or shaley soils (greater than 35 percent by volume). Mineral SOC stocks were estimated using a Tier 2 method for these areas because the Century model, which is used for the Tier 3 method, has not been fully tested to address its adequacy for estimating C stock changes associated with certain crops and rotations, as well as cobbly, gravelly, or shaley soils. An additional stock change calculation was made for mineral soils using Tier 2 emission factors, accounting for enrollment patterns in the Conservation Reserve Program after 2003, which was not addressed by the Tier 3 methods.

Further elaboration on the methodology and data used to estimate stock changes from mineral soils are described below and in Annex 3.13.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), which simulates the dynamics of C and other elements in cropland, grassland, forest, and savanna ecosystems. It uses monthly weather data as an input, along with information about soil physical properties. Input data on land use and management are specified at monthly resolution and include land-use type, crop/forage type, and management activities (e.g., planting, harvesting, fertilization, manure amendments, tillage, irrigation, residue removal, grazing, and fire). The model computes net primary productivity and C additions to soil, soil temperature, and water dynamics, in addition to turnover, stabilization, and mineralization of soil organic matter C and nutrient (N, K, S) elements. This method is more accurate than the Tier 1 and 2 approaches provided by the IPCC, because the simulation model treats changes as continuous over time rather than the simplified discrete changes represented in the default method (see Box 7-3 for additional information). National estimates were obtained by simulating historical land-use and management patterns as recorded in the USDA National Resources Inventory (NRI) survey.

[BEGIN BOX]

Box 7-3: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches

A Tier 3 model-based approach is used to inventory soil C stock changes on the majority of agricultural land with mineral soils. This approach entails several fundamental differences compared to the IPCC Tier 1 or 2 methods, which are based on a classification of land areas into a number of discrete classes based on a highly aggregated classification of climate, soil, and management (i.e., only six climate regions, seven soil types and eleven management systems occur in U.S. agricultural land under the IPCC classification). Input variables to the Tier 3 model, including climate, soils, and management activities (e.g., fertilization, crop species, tillage, etc.), are represented in considerably more detail both temporally and spatially, and exhibit multi-dimensional interactions through the more complex model structure compared with the IPCC Tier 1 or 2 approach. The spatial resolution of

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[183] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began. Therefore, the classification prior to 2002 was based on less than 20 years of recorded land-use history for the time series.

the analysis is also finer in the Tier 3 method compared to the lower tier methods as implemented in the United States for previous Inventories (e.g., 3,037 counties versus 181 Major Land Resource Areas (MLRAs), respectively).

In the Century model, soil C dynamics (and CO_2 emissions and uptake) are treated as continuous variables, which change on a monthly time step. Carbon emissions and removals are an outcome of plant production and decomposition processes, which are simulated in the model structure. Thus, changes in soil C stocks are influenced by not only changes in land use and management but also inter-annual climate variability and secondary feedbacks between management activities, climate, and soils as they affect primary production and decomposition. This latter characteristic constitutes one of the greatest differences between the methods, and forms the basis for a more complete accounting of soil C stock changes in the Tier 3 approach compared with Tier 2 methodology.

Because the Tier 3 model simulates a continuous time period rather than the equilibrium step change used in the IPCC methodology (Tier 1 and 2), the Tier 3 model addresses the delayed response of soils to management and land-use changes. Delayed responses can occur due to variable weather patterns and other environmental constraints that interact with land use and management and affect the time frame over which stock changes occur. Moreover, the Tier 3 method also accounts for the overall effect of increasing yields and, hence, C input to soils that have taken place across management systems and crop types within the United States. Productivity has increased by 1 to 2 percent annually over the past 4 to 5 decades for most major crops in the United States (Reilly and Fuglie 1998), which is believed to have led to increases in cropland soil C stocks (e.g., Allmaras et al. 2000). This is a major difference from the IPCC-based Tier 1 and 2 approaches, in which trends in soil C stocks only capture discrete changes in management and/or land use, rather than a longer term trend such as gradual increases in crop productivity.

[END BOX]

Additional sources of activity data were used to supplement the land-use information from NRI. The Conservation Technology Information Center (CTIC 1998) provided annual data on tillage activity at the county level since 1989, with adjustments for long-term adoption of no-till agriculture (Towery 2001). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to cropland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the amended area. The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management section (Section 6.2) and annex (Annex 3.10).

Manure amendments were an input to the Century Model based on manure N available for application from all managed or unmanaged systems except Pasture/Range/Paddock.[184] Data on the county-level N available for application were estimated for managed systems based on the total amount of N excreted in manure minus N losses during storage and transport, and including the addition of N from bedding materials. Nitrogen losses include direct nitrous oxide emissions, volatilization of ammonia and NO_x, runoff and leaching, and poultry manure used as a feed supplement. More information on these losses is available in the description of the Manure Management source category. For unmanaged systems, it is assumed that no N losses or additions occur prior to the application of manure to the soil.

Monthly weather data were used as an input in the model simulations, based on an aggregation of gridded weather data to the county scale from the Parameter-elevation Regressions on Independent Slopes Model (PRISM) database

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[184] Pasture/Range/Paddock manure additions to soils are addressed in the *Grassland Remaining Grassland* and *Land Converted to Grassland* categories.

(Daly et al. 1994). Soil attributes, which were obtained from an NRI database, were assigned based on field visits and soil series descriptions. Each NRI point was run 100 times as part of the uncertainty assessment, yielding a total of over 18 million simulation runs for the analysis. Carbon stock estimates from Century were adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Ogle et al. 2007, 2010). C stocks and 95 percent confidence intervals were estimated for each year between 1990 and 2003, but C stock changes from 2004 to 2009 were assumed to be similar to 2003 because no additional activity data are currently available from the NRI for the latter years.

Tier 2 Approach

In the IPCC Tier 2 method, data on climate, soil types, land-use, and land management activity were used to classify land area to apply appropriate stock change factors. MLRAs formed the base spatial unit for mapping climate regions in the United States; each MLRA represents a geographic unit with relatively similar soils, climate, water resources, and land uses (NRCS 1981). MLRAs were classified into climate regions according to the IPCC categories using the PRISM climate database of Daly et al. (1994).

Reference C stocks were estimated using the National Soil Survey Characterization Database (NRCS 1997) with cultivated cropland as the reference condition, rather than native vegetation as used in IPCC (2003, 2006). Changing the reference condition was necessary because soil measurements under agricultural management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997) than those that are not considered cultivated cropland.

U.S.-specific stock change factors were derived from published literature to determine the impact of management practices on SOC storage, including changes in tillage, cropping rotations and intensification, and land-use change between cultivated and uncultivated conditions (Ogle et al. 2003, Ogle et al. 2006). U.S. factors associated with organic matter amendments were not estimated because there were an insufficient number of studies to analyze those impacts. Instead, factors from IPCC (2003) were used to estimate the effect of those activities. Euliss and Gleason (2002) provided the data for computing the change in SOC storage resulting from restoration of wetland enrolled in the Conservation Reserve Program.

Activity data were primarily based on the historical land-use/management patterns recorded in the NRI. Each NRI point was classified by land use, soil type, climate region (using PRISM data, Daly et al. 1994) and management condition. Classification of cropland area by tillage practice was based on data from the Conservation Tillage Information Center (CTIC 1998, Towery 2001) as described above. Activity data on wetland restoration of Conservation Reserve Program land were obtained from Euliss and Gleason (2002). Manure N amendments over the inventory time period were based on application rates and areas amended with manure N from Edmonds et al. (2003), in addition to the managed manure production data discussed in the previous methodology subsection on the Tier 3 analysis for mineral soils.

Combining information from these data sources, SOC stocks for mineral soils were estimated 50,000 times for 1982, 1992, and 1997, using a Monte Carlo simulation approach and the probability distribution functions for U.S.-specific stock change factors, reference C stocks, and land-use activity data (Ogle et al. 2002, Ogle et al. 2003). The annual C flux for 1990 through 1992 was determined by calculating the average annual change in stocks between 1982 and 1992; annual C flux for 1993 through 2009 was determined by calculating the average annual change in stocks between 1992 and 1997.

Additional Mineral C Stock Change

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with gains or losses in soil C after 2003 due to changes in Conservation Reserve Program enrollment. The change in enrollment acreage relative to 2003 was based on data from USDA-FSA (2009) for 2004 through 2009, and the differences in mineral soil areas were multiplied by 0.5 metric tons C per hectare per year to estimate the net effect on soil C stocks. The stock change rate is based on estimations using the IPCC method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Cropland Remaining Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Cropland Remaining Cropland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty associated with the *Cropland Remaining Cropland* land-use category was addressed for changes in agricultural soil C stocks (including both mineral and organic soils). Uncertainty estimates are presented in Table 7-19 for mineral soil C stocks and organic soil C stocks disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006). The combined uncertainty was calculated by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. More details on how the individual uncertainties were developed are in Annex 3.13. The combined uncertainty for soil C stocks in *Cropland Remaining Cropland* ranged from 172 percent below to 167 percent above the 2009 stock change estimate of -17.4 Tg CO_2 Eq.

Table 7-19: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Cropland Remaining Cropland* (Tg CO_2 Eq. and Percent)

Source	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)**		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 3 Inventory Methodology	(42.3)	(69.6)	(15.1)	-64%	+64%
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	(3.0)	(6.9)	0.8	-127%	+128%
Mineral Soil C Stocks: Cropland Remaining Cropland (Change in CRP enrollment relative to 2003)	(0.3)	(0.1)	(0.4)	-50%	+50%
Organic Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	27.7	15.8	36.9	-43%	+33%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stock Change in Cropland Remaining Cropland	**(17.4)**	**(47.3)**	**11.6**	**-172%**	**+167%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled throughout the inventory process. As discussed in the uncertainty section, results were compared to field measurements, and a statistical relationship was developed to assess uncertainties in the model's predictive capability. The comparisons included over 40 long-term experiments, representing about 800 combinations of management treatments across all of the sites (Ogle et al. 2007). Inventory reporting forms and text were reviewed and revised as needed to correct transcription errors.

Planned Improvements

The first improvement is to update the Tier 2 inventory analysis with the latest annual National Resources Inventory (NRI) data. While the land base for the Tier 3 approach uses the latest available data from the NRI, the Tier 2 portion of the Inventory has not updated and is based on the Revised 1997 NRI data product (USDA-NRCS 2000).

This improvement will extend the time series of the land use data from 1997 through 2003 for the Tier 2 portion of the Inventory.

The second improvement is to incorporate remote sensing in the analysis for estimation of crop and forage production, and conduct the Tier 3 assessment of soil C stock changes and soil nitrous oxide emissions in a single analysis. Specifically, the Enhanced Vegetation Index (EVI) product that is derived from MODIS satellite imagery is being used to refine the production estimation for the Tier 3 assessment framework based on the DAYCENT simulation model. EVI reflects changes in plant "greenness" over the growing season and can be used to compute production based on the light use efficiency of the crop or forage (Potter et al. 1993). In the current framework, production is simulated based on the weather data, soil characteristics, and the genetic potential of the crop. While this method produces reasonable results, remote sensing can be used to refine the productivity estimates and reduce biases in crop production and subsequent C input to soil systems. It is anticipated that precision in the Tier 3 assessment framework will be increased by 25 percent or more with the new method. In addition, DAYCENT is currently used for estimating soil nitrous oxide emissions in the Inventory, and can also be used to estimate soil organic C stock changes using the same algorithms in the CENTURY model. Simulating both soil C stock changes and nitrous oxide emissions in a single analysis will ensure consistency in the treatment of these sources, which are coupled through the N and C cycles in agricultural systems.

CO_2 Emissions from Agricultural Liming

IPCC (2006) recommends reporting CO_2 emissions from lime additions (in the form of crushed limestone ($CaCO_3$) and dolomite ($CaMg(CO_3)_2$) to agricultural soils. Limestone and dolomite are added by land managers to ameliorate acidification. When these compounds come in contact with acid soils, they degrade, thereby generating CO_2. The rate and ultimate magnitude of degradation of applied limestone and dolomite depends on the soil conditions, climate regime, and the type of mineral applied. Emissions from liming have fluctuated over the past nineteen years, ranging from 3.8 Tg CO_2 Eq. to 5.0 Tg CO_2 Eq. In 2009, liming of agricultural soils in the United States resulted in emissions of 4.2 Tg CO_2 Eq. (1.2 Tg C), representing about a 10 percent decrease in emissions since 1990 (see Table 7-20 and Table 7-21). The trend is driven entirely by the amount of lime and dolomite estimated to have been applied to soils over the time period.

Table 7-20: Emissions from Liming of Agricultural Soils (Tg CO_2 Eq.)

Source	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Liming of Soils[1]	4.7		4.3		4.3	4.2	4.5	5.0	4.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*.

Table 7-21: Emissions from Liming of Agricultural Soils (Tg C)

Source	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Liming of Soils[1]	1.3		1.2		1.2	1.2	1.2	1.4	1.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.
[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*.

Methodology

CO_2 emissions from degradation of limestone and dolomite applied to agricultural soils were estimated using a Tier 2 methodology consistent with IPCC (2006). The annual amounts of limestone and dolomite applied (see Table 7-22) were multiplied by CO_2 emission factors from West and McBride (2005). These emission factors (0.059 metric ton C/metric ton limestone, 0.064 metric ton C/metric ton dolomite) are lower than the IPCC default emission factors because they account for the portion of agricultural lime that may leach through the soil and travel by rivers to the ocean (West and McBride 2005). This analysis of lime dissolution is based on liming occurring in the Mississippi River basin, where the vast majority of all U.S. liming takes place (West 2008). U.S. liming that does not occur in the Mississippi River basin tends to occur under similar soil and rainfall regimes, and, thus, the emission factor is appropriate for use across the United States (West 2008). The annual application rates of limestone and dolomite were derived from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Industry Surveys* (Tepordei 1993 through 2006; Willett 2007a, b, 2009 through 2010; USGS 2008 through

2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying crushed stone manufacturers. Because some manufacturers were reluctant to provide information, the estimates of total crushed limestone and dolomite production and use were divided into three components: (1) production by end-use, as reported by manufacturers (i.e., “specified” production); (2) production reported by manufacturers without end-uses specified (i.e., “unspecified” production); and (3) estimated additional production by manufacturers who did not respond to the survey (i.e., “estimated” production).

The “unspecified” and “estimated” amounts of crushed limestone and dolomite applied to agricultural soils were calculated by multiplying the percentage of total “specified” limestone and dolomite production applied to agricultural soils by the total amounts of “unspecified” and “estimated” limestone and dolomite production. In other words, the proportion of total “unspecified” and “estimated” crushed limestone and dolomite that was applied to agricultural soils (as opposed to other uses of the stone) was assumed to be proportionate to the amount of “specified” crushed limestone and dolomite that was applied to agricultural soils. In addition, data were not available for 1990, 1992, and 2009 on the fractions of total crushed stone production that were limestone and dolomite, and on the fractions of limestone and dolomite production that were applied to soils. To estimate the 1990 and 1992 data, a set of average fractions were calculated using the 1991 and 1993 data. These average fractions were applied to the quantity of "total crushed stone produced or used" reported for 1990 and 1992 in the 1994 *Minerals Yearbook* (Tepordei 1996). To estimate 2009 data, the previous year’s fractions were applied to a 2009 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2010* (USGS 2010); thus, the 2009 data in Table 7-20 through Table 7-22 are shaded to indicate that they are based on a combination of data and projections.

The primary source for limestone and dolomite activity data is the *Minerals Yearbook*, published by the Bureau of Mines through 1994 and by the USGS from 1995 to the present. In 1994, the “Crushed Stone” chapter in the *Minerals Yearbook* began rounding (to the nearest thousand metric tons) quantities for total crushed stone produced or used. It then reported revised (rounded) quantities for each of the years from 1990 to 1993. In order to minimize the inconsistencies in the activity data, these revised production numbers have been used in all of the subsequent calculations. Since limestone and dolomite activity data are also available at the state level, the national-level estimates reported here were broken out by state, although state-level estimates are not reported here.

Table 7-22: Applied Minerals (Million Metric Tons)

Mineral	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Limestone	19.01	15.86	18.09	16.54	17.46	20.55	17.20
Dolomite	2.36	3.81	1.85	2.73	2.92	2.54	2.13

Note: These numbers represent amounts applied to *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*, and *Settlements Remaining Settlements*. Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

Uncertainty and Time-Series Consistency

Uncertainty regarding limestone and dolomite activity data inputs was estimated at ±15 percent and assumed to be uniformly distributed around the inventory estimate (Tepordei 2003b). Analysis of the uncertainty associated with the emission factors included the following: the fraction of agricultural lime dissolved by nitric acid versus the fraction that reacts with carbonic acid, and the portion of bicarbonate that leaches through the soil and is transported to the ocean. Uncertainty regarding the time associated with leaching and transport was not accounted for, but should not change the uncertainty associated with CO_2 emissions (West 2005). The uncertainties associated with the fraction of agricultural lime dissolved by nitric acid and the portion of bicarbonate that leaches through the soil were each modeled as a smoothed triangular distribution between ranges of zero percent to 100 percent. The uncertainty surrounding these two components largely drives the overall uncertainty estimates reported below. More information on the uncertainty estimates for Liming of Agricultural Soils is contained within the Uncertainty Annex.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 emissions from liming. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-23. CO_2 emissions from Liming of Agricultural Soils in 2008 were estimated to be between 0.1 and 8.4 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 97 percent below to 99 percent above the 2009 emission estimate of 4.2 Tg CO_2 Eq.

Table 7-23: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Liming of Agricultural Soils (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Liming of Agricultural Soils[1]	CO_2	4.2	0.1	8.4	-97%	+99%

[a]Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

[1] Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland,* and *Settlements Remaining Settlements*.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

Several adjustments were made in the current Inventory to improve the results. The quantity of applied minerals reported in the previous Inventory for 2007 has been revised; the updated activity data for 2007 are approximately 1,480 thousand metric tons greater than the data used for the previous Inventory, consequently, the reported emissions resulting from liming in 2007 increased by about 8.4 percent. In the previous Inventory, to estimate 2008 data, the previous year's fractions were applied to a 2008 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2009* (USGS 2009). Since publication of the previous Inventory, the *Minerals Yearbook* has published actual quantities of crushed stone sold or used by producers in the United States in 2008. These values have replaced those used in the previous Inventory to calculate the quantity of minerals applied to soil and the emissions from liming. The updated activity data for 2008 are approximately 5,460 thousand metric tons greater than the data used in the previous Inventory. As a result, the reported emissions from liming in 2008 increased by about 36 percent.

CO_2 Emissions from Urea Fertilization

The use of urea ($CO(NH_2)_2$) as fertilizer leads to emissions of CO_2 that was fixed during the industrial production process. Urea in the presence of water and urease enzymes is converted into ammonium (NH_4^+), hydroxyl ion (OH^-), and bicarbonate (HCO_3^-). The bicarbonate then evolves into CO_2 and water. Emissions from urea fertilization in the United States totaled 3.6 Tg CO_2 Eq. (1.0 Tg C) in 2009 (Table 7-24 and Table 7-25). Emissions from urea fertilization have grown 49 percent between 1990 and 2009, due to an increase in the use of urea as fertilizer.

Table 7-24: CO_2 Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg CO_2 Eq.)

Source	1990		2000		2005	2006	2007	2008	2009
Urea Fertilization[1]	2.4		3.2		3.5	3.7	3.7	3.6	3.6

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Table 7-25: CO_2 Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg C)

Source	1990		2000		2005	2006	2007	2008	2009
Urea Fertilization[1]	0.7		0.9		1.0	1.0	1.0	1.0	1.0

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] Also includes emissions from urea fertilization on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Methodology

Carbon dioxide emissions from the application of urea to agricultural soils were estimated using the IPCC (2006) Tier 1 methodology. The annual amounts of urea fertilizer applied (see Table 7-26) were derived from state-level fertilizer sales data provided in *Commercial Fertilizers* (TVA 1991, 1992, 1993, 1994; AAPFCO 1995 through 2010) and were multiplied by the default IPCC (2006) emission factor of 0.20, which is equal to the C content of urea on an atomic weight basis. Because fertilizer sales data are reported in fertilizer years (July through June), a calculation was performed to convert the data to calendar years (January through December). According to historic monthly fertilizer use data (TVA 1992b), 65 percent of total fertilizer used in any fertilizer year is applied between January and June of that calendar year, and 35 percent of total fertilizer used in any fertilizer year is applied between July and December of the previous calendar year. Fertilizer sales data for the 2009 fertilizer year were not available in time for publication. Accordingly, urea application in the 2009 fertilizer year was assumed to be equal to that of the 2008 fertilizer year. Since 2010 fertilizer year data were not available, July through December 2009 fertilizer consumption was assumed to be equal to July through December 2008 fertilizer consumption; thus, the 2009 data in Table 7-24 through Table 7-26 are shaded to indicate that they are based on a combination of data and projections. State-level estimates of CO_2 emissions from the application of urea to agricultural soils were summed to estimate total emissions for the entire United States.

Table 7-26: Applied Urea (Million Metric Tons)

	1990		2000		2005	2006	2007	2008	2009
Urea Fertilizer[1]	3.30		4.38		4.78	4.98	5.10	4.92	4.92

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

[1] These numbers represent amounts applied to all agricultural land, including *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-27 for Urea Fertilization. A Tier 2 Monte Carlo analysis was completed. The largest source of uncertainty was the default emission factor, which assumes that 100 percent of the C applied to soils is ultimately emitted into the environment as CO_2. This factor does not incorporate the possibility that some of the C may be retained in the soil. The emission estimate is, thus, likely to be high. In addition, each urea consumption data point has an associated uncertainty. Urea for non-fertilizer use, such as aircraft deicing, may be included in consumption totals; it was determined through personal communication with Fertilizer Regulatory Program Coordinator David L. Terry (2007), however, that this amount is most likely very small. Research into aircraft deicing practices also confirmed that urea is used minimally in the industry; a 1992 survey found a known annual usage of approximately 2,000 tons of urea for deicing; this would constitute 0.06 percent of the 1992 consumption of urea (EPA 2000). Similarly, surveys conducted from 2002 to 2005 indicate that total urea use for deicing at U.S. airports is estimated to be 3,740 MT per year, or less than 0.07 percent of the fertilizer total for 2007 (Itle 2009). Lastly, there is uncertainty surrounding the assumptions behind the calculation that converts fertilizer years to calendar years. CO_2 emissions from urea fertilization of agricultural soils in 2009 were estimated to be between 2.1 and 3.7 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 43 percent below to 3 percent above the 2009 emission estimate of 3.6 Tg CO_2 Eq.

Table 7-27: Quantitative Uncertainty Estimates for CO_2 Emissions from Urea Fertilization (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emissions Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Urea Fertilization	CO_2	3.6	2.1	3.7	-43%	+3%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: These numbers represent amounts applied to all agricultural land, *including Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. Inventory reporting forms and text were reviewed. No errors were found.

Recalculations Discussion

July to December 2007 urea application data were updated with assumptions for fertilizer year 2008, and the 2007 emission estimate was revised accordingly. The activity data decreased about 800,000 metric tons for 2007 and this change resulted in an approximately 3 percent decrease in emissions in 2007 relative to the previous Inventory. In the previous Inventory, the application for this period was calculated based on application during July to December 2006. January to June 2008 data were also used to update 2008 emission estimates. The activity data decreased about 270,000 metric tons for 2008, resulting in an approximately 5 percent decrease in emissions in 2008 relative to the previous Inventory.

Planned Improvements

The primary planned improvement is to investigate using a Tier 2 or Tier 3 approach, which would utilize country-specific information to estimate a more precise emission factor.

7.5. Land Converted to Cropland (IPCC Source Category 5B2)

Land Converted to Cropland includes all cropland in an inventory year that had been another land use at any point during the previous 20 years[185] according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by the IPCC guidelines (IPCC 2006) unless there is another land-use change. The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Land Converted to Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Cropland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. The IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[186]

Land-use and management of mineral soils in *Land Converted to Cropland* generally led to relatively small increases in soil C during the 1990s but the pattern changed to small losses of C through the latter part of the time series (Table 7-28 and Table 7-29). The total rate of change in soil C stocks was 5.9 Tg CO_2 Eq. (1.6 Tg C) in 2009. Mineral soils were estimated to lose 3.3 Tg CO_2 Eq. (0.9 Tg C) in 2009, while drainage and cultivation of organic soils led to annual losses of 2.6 Tg CO_2 Eq. (0.7 Tg C) in 2009.

Table 7-28: Net CO_2 Flux from Soil C Stock Changes in Land *Converted to Cropland* (Tg CO_2 Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(0.3)	(0.3)	3.3	3.3	3.3	3.3	3.3
Organic Soils	2.4	2.6	2.6	2.6	2.6	2.6	2.6
Total Net Flux	**2.2**	**2.4**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-29: Net CO_2 Flux from Soil C Stock Changes in *Land Converted to Cropland* (Tg C)

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[185] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[186] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(0.1)	(0.1)	0.9	0.9	0.9	0.9	0.9
Organic Soils	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total Net Flux	**0.6**	**0.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils for *Land Converted to Cropland* is displayed in Figure 7-7 and Figure 7-8. While a large portion of the United States had net losses of soil C for *Land Converted to Cropland*, there were some notable areas with net C accumulation in the Great Plains, Midwest, mid-Atlantic states. These areas were gaining C following conversion, because the land had been brought into hay production, including grass and legume hay, leading to enhanced plant production relative to the previous land use, and thus higher C input to the soil. Emissions from organic soils were largest in California, Florida, and the upper Midwest, which coincided with largest concentrations of cultivated organic soils in the United States.

Figure 7-7: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Figure 7-8: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Land Converted to Cropland*. Further elaboration on the methodologies and data used to estimate stock changes for mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Cropland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Cropland* in a given year between 1990 and 2009 if the land use was cropland but had been another use during the previous 20 years. Cropland includes all land used to produce food or fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

A Tier 3 model-based approach was applied to estimate C stock changes for soils on *Land Converted to Cropland* used to produce a majority of all crops (Ogle et al. 2010). Soil C stock changes on the remaining soils were estimated with the IPCC Tier 2 method (Ogle et al. 2003), including land used to produce vegetable, tobacco, perennial/horticultural crops, and rice; land on very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.[187]

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model for the Tier 3

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[187] Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

methods. National estimates were obtained by using the model to simulate historical land-use change patterns as recorded in the USDA National Resources Inventory (USDA-NRCS 2000). The methods used for *Land Converted to Cropland* are the same as those described in the Tier 3 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 3 methods section and Annex 3.13 for additional information).

Tier 2 Approach

For the mineral soils not included in the Tier 3 analysis, SOC stock changes were estimated using a Tier 2 Approach for *Land Converted to Cropland* as described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section for additional information).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Land Converted to Cropland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty for annual C emission estimates from drained organic soils in *Land Converted to Cropland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-30 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Land Converted to Cropland* was estimated to be 40 percent below and 36 percent above the inventory estimate of 5.9 Tg CO_2 Eq.

Table 7-30: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Cropland* (Tg CO_2 Eq. and Percent)

Source	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)**		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mineral Soil C Stocks: Land Converted to Cropland, Tier 3 Inventory Methodology	(0.8)	(1.5)	(0.1)	-84%	+84%
Mineral Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	4.1	2.3	5.8	-44%	+41%
Organic Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	2.6	1.2	3.7	-53%	+41%
Combined Uncertainty for Flux associated with Soil Carbon Stock Change in Land Converted to Cropland	**5.9**	**3.5**	**8.1**	**-40%**	**+36%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See QA/QC and Verification section under *Cropland Remaining Cropland*.

Planned Improvements

The empirically-based uncertainty estimator described in the *Cropland Remaining Cropland* section for the Tier 3 approach has not been developed to estimate uncertainties related to the structure of the Century model for *Land Converted to Cropland,* but this is a planned improvement. This improvement will produce a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.6. Grassland Remaining Grassland (IPCC Source Category 5C1)

Grassland Remaining Grassland includes all grassland in an inventory year that had been grassland for the previous 20 years[188] according to the USDA NRI land use survey (USDA-NRCS 2000). The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area in *Grassland Remaining Grassland* (see Section 7.1) and the grassland area included in the Inventory. While federal grasslands probably have minimal changes in land management and C stocks, plans are being made to further evaluate and potentially include these areas in future C inventories.

Background on agricultural C stock changes is provided in the *Cropland Remaining Cropland* section and will only be summarized here for *Grassland Remaining Grassland.* Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared to soils. IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[189]

Land-use and management of mineral soils in *Grassland Remaining Grassland* increased soil C, while organic soils lost relatively small amounts of C in each year 1990 through 2009. Due to the pattern for mineral soils, the overall trend was a gain in soil C over the time series although the rates varied from year to year, with a net removal of 8.3 Tg CO_2 Eq. (2.3 Tg C) in 2009. There was considerable variation over the time series driven by variability in weather patterns and associated interaction with land management activity. The change rates on per hectare basis were small, however, even in the years with larger total changes in stocks. Overall, flux rates declined by 43.8 Tg CO_2 Eq. (12.0 Tg C) when comparing the net change in soil C from 1990 and 2009.

Table 7-31: Net CO_2 Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (Tg CO_2 Eq.)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(56.0)	(56.3)	(12.6)	(12.4)	(12.3)	(12.2)	(12.0)
Organic Soils	3.9	3.7	3.7	3.7	3.7	3.7	3.7
Total Net Flux	**(52.2)**	**(52.6)**	**(8.9)**	**(8.8)**	**(8.6)**	**(8.5)**	**(8.3)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-32: Net CO_2 Flux from Soil C Stock Changes in Grassland Remaining Grassland (Tg C)

Soil Type	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils	(15.3)	(15.3)	(3.4)	(3.4)	(3.4)	(3.3)	(3.3)
Organic Soils	1.1	1.0	1.0	1.0	1.0	1.0	1.0
Total Net Flux	**(14.2)**	**(14.3)**	**(2.4)**	**(2.4)**	**(2.3)**	**(2.3)**	**(2.3)**

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[188] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[189] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO_2 flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-9 and Figure 7-10. Grassland gained soil organic C in several regions during 2009, including the Northeast, Midwest, Southwest and far western states; although these were relatively small increases in C on a per-hectare basis. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-9: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Figure 7-10: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Grassland Remaining Grassland*. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Grassland Remaining Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Grassland Remaining Grassland* in a given year between 1990 and 2009 if the land use had been grassland for 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for most mineral soils in *Grassland Remaining Grassland*. The C stock changes for the remaining soils were estimated with an IPCC Tier 2 method (Ogle et al. 2003), including gravelly, cobbly, or shaley soils (greater than 35 percent by volume) and additional stock changes associated with sewage sludge amendments.

Tier 3 Approach

Mineral soil organic C stocks and stock changes for *Grassland Remaining Grassland* were estimated using the Century biogeochemical model, as described in *Cropland Remaining Cropland*. Historical land-use and management patterns were used in the Century simulations as recorded in the USDA National Resources Inventory (NRI) survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to grassland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds, et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the amended area.

The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management Section (Section 6.2) and Annex (Annex 3.10). In contrast to manure amendments, Pasture/Range/Paddock (PRP) manure N deposition was estimated internally in the Century model, as part of the grassland system simulations (i.e., PRP manure deposition was not an external input into the model). See the Tier 3 methods in *Cropland Remaining Cropland* section for additional discussion on the Tier 3 methodology for mineral soils.

Tier 2 Approach

The Tier 2 approach is based on the same methods described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section and Annex 3.13 for additional information).

Additional Mineral C Stock Change Calculations

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with sewage sludge amendments using a Tier 2 method. Estimates of the amounts of sewage sludge N applied to agricultural land were derived from national data on sewage sludge generation, disposition, and N content. Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, were obtained from an EPA report (EPA 1999) and estimates for 2004 were obtained from an independent national biosolids survey (NEBRA 2007). These values were linearly interpolated to estimate values for the intervening years. N application rates from Kellogg et al. (2000) were used to determine the amount of area receiving sludge amendments. Although sewage sludge can be added to land managed for other land uses, it was assumed that agricultural amendments occur in grassland. Cropland is assumed to rarely be amended with sewage sludge due to the high metal content and other pollutants in human waste. The soil C storage rate was estimated at 0.38 metric tons C per hectare per year for sewage sludge amendments to grassland. The stock change rate is based on country-specific factors and the IPCC default method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Grassland Remaining Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Grassland Remaining Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-33 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Grassland Remaining Grassland* was estimated to be 32 percent below and 25 percent above the inventory estimate of -8.3 Tg CO_2 Eq.

Table 7-33: Tier 2 Quantitative Uncertainty Estimates for C Stock Changes occurring within *Grassland Remaining Grassland* (Tg CO_2 Eq. and Percent)

Source	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)**		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mineral Soil C Stocks Grassland Remaining Grassland, Tier 3 Methodology	(10.6)	(11.4)	(9.8)	-7%	+7%

Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	(0.2)	(0.3)	0.0	-89%	+127%
Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology (Change in Soil C due to Sewage Sludge Amendments)	(1.2)	(1.9)	(0.6)	-50%	+50%
Organic Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	3.7	1.2	5.5	-66%	+49%
Combined Uncertainty for Flux Associated with Agricultural Soil Carbon Stock Change in Grassland Remaining Grassland	**(8.3)**	**(11.0)**	**(6.3)**	**-32%**	**+25%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Uncertainties in Mineral Soil Carbon Stock Changes

The uncertainty analysis for *Grassland Remaining Grassland* using the Tier 3 approach and Tier 2 approach were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. See the Tier 3 approach for mineral soils under the *Cropland Remaining Cropland* section for additional discussion.

A ±50 percent uncertainty was assumed for additional adjustments to the soil C stocks between 1990 and 2009 to account for additional C stock changes associated with amending grassland soils with sewage sludge.

Uncertainties in Soil Carbon Stock Changes for Organic Soils

Uncertainty in C emissions from organic soils was estimated using country-specific factors and a Monte Carlo analysis. Probability distribution functions for emission factors were derived from a synthesis of 10 studies, and combined with uncertainties in the NRI land use and management data for organic soils in the Monte Carlo analysis. See the Tier 2 section under minerals soils of *Cropland Remaining Cropland* for additional discussion.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled through the inventory process. A minor error was found in the post-processing results to compute the final totals, which was corrected. No additional errors were found.

Recalculations Discussion

There were minor changes in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information. The revised areas led to small changes in the soil C stock changes for *Grassland Remaining Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil N_2O emissions into a single analysis. This improvement will ensure that the N and C cycles are treated consistently in the Inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.7. Land Converted to Grassland (IPCC Source Category 5C2)

Land Converted to Grassland includes all grassland in an inventory year that had been in another land use at any point during the previous 20 years[190] according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by IPCC (2006) unless there is another land use change. The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area for *Land Converted to Grassland* (see Section 7.1) and the grassland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Grassland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. IPCC (2006) recommend reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.[191]

Land-use and management of mineral soils in *Land Converted to Grassland* led to an increase in soil C stocks from 1990 through 2009, which was largely due to annual cropland conversion to pasture (see Table 7-34 and Table 7-35). For example, the stock change rates were estimated to remove 20.3 Tg CO_2 Eq./yr (5.5 Tg C) and 24.5 Tg CO_2 Eq./yr (6.7 Tg C) from mineral soils in 1990 and 2009, respectively. Drainage of organic soils for grazing management led to losses varying from 0.5 to 0.9 Tg CO_2 Eq./yr (0.1 to 0.2 Tg C).

Table 7-34: Net CO_2 Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg CO_2 Eq.)

Soil Type	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils[a]	(20.3)		(28.1)		(25.3)	(25.1)	(24.9)	(24.7)	(24.5)
Organic Soils	0.5		0.9		0.9	0.9	0.9	0.9	0.9
Total Net Flux	**(19.8)**		**(27.2)**		**(24.4)**	**(24.2)**	**(24.0)**	**(23.8)**	**(23.6)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.
[a] Stock changes due to application of sewage sludge are reported in *Grassland Remaining Grassland*.

Table 7-35: Net CO_2 Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg C)

Soil Type	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Mineral Soils[a]	(5.5)		(7.7)		(6.9)	(6.8)	(6.8)	(6.7)	(6.7)
Organic Soils	0.1		0.2		0.2	0.2	0.2	0.2	0.2
Total Net Flux	**(5.4)**		**(7.4)**		**(6.7)**	**(6.6)**	**(6.5)**	**(6.5)**	**(6.4)**

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.
[a] Stock changes due to application of sewage sludge in *Land Converted to Grassland* are reported in *Grassland Remaining Grassland*.

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The spatial variability in annual CO_2 flux associated with C stock changes in mineral soils is displayed in Figure 7-11and Figure 7-12. Soil C stock increased in most states for *Land Converted to Grassland*. The largest gains were in the South-Central region, Midwest, and northern Great Plains. The patterns were driven by conversion of annual cropland into continuous pasture. Emissions from organic soils were largest in California, Florida, and the upper Midwest, coinciding with largest concentrations of organic soils in the United States that are used for agricultural production.

Figure 7-11: Total Net Annual CO_2 Flux for Mineral Soils under Agricultural Management within States, 2009,

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[190] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

[191] CO_2 emissions associated with liming are also estimated but included in a separate section of the report.

Land Converted to Grassland

Figure 7-12: Total Net Annual CO_2 Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Grassland*

Methodology

This section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral soils for *Land Converted to Grassland*. Biomass C stock changes are not explicitly included in this category but losses of associated with conversion of forest to grassland are included in the *Forest Land Remaining Forest Land* section. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Grassland* in a given year between 1990 and 2009 if the land use was grassland, but had been another use in the previous 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangeland typically includes extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for *Land Converted to Grassland* on most mineral soils. C stock changes on the remaining soils were estimated with an IPCC Tier 2 approach (Ogle et al. 2003), including prior cropland used to produce vegetables, tobacco, perennial/horticultural crops, and rice; land areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.[192] A Tier 2 approach was also used to estimate additional changes in mineral soil C stocks due to sewage sludge amendments. However, stock changes associated with sewage sludge amendments are reported in the *Grassland Remaining Grassland* section.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model as described for *Grassland Remaining Grassland*. Historical land-use and management patterns were used in the Century simulations as recorded in the NRI survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and the National Agricultural Statistics Service (NASS 1992, 1999, 2004) (see *Grassland Remaining Grassland* Tier 3 methods section for additional information).

Tier 2 Approach

The Tier 2 approach used for *Land Converted to Grassland* on mineral soils is the same as described for *Cropland Remaining Cropland* (See *Cropland Remaining Cropland* Tier 2 Approach and Annex 3.13 for additional information).

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[192] Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Land Converted to Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described in *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty or annual C emission estimates from drained organic soils in *Land Converted to Grassland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-36 for each subsource (i.e., mineral soil C stocks and organic soil C stocks), disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006) (i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities). The combined uncertainty for soil C stocks in *Land Converted to Grassland* ranged from 15 percent below to 15 percent above the 2009 estimate of -23.6 Tg CO_2 Eq.

Table 7-36: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Grassland* (Tg CO_2 Eq. and Percent)

Source	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate**			
		(Tg CO_2 Eq.)		**(%)**	
		Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Mineral Soil C Stocks: Land Converted to Grassland, Tier 3 Inventory Methodology	(19.5)	(22.2)	(16.7)	-14%	+14%
Mineral Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	(5.0)	(7.0)	(2.8)	-39%	+43%
Organic Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	0.9	0.2	1.8	-76%	+104%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stocks in Land Converted to Grassland	**(23.6)**	**(27.0)**	**(20.0)**	**-15%**	**+15%**

Note: Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

See the QA/QC and Verification section under *Grassland Remaining Grassland*.

Recalculations Discussion

There were minor changes in the current Inventory relative to the previous version in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information). The revised areas led to small changes in the soil C stock changes for *Land Converted to Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil nitrous oxide emissions into a single analysis. This improvement will ensure that the nitrogen and carbon cycles are treated consistently in the national inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.8. Wetlands Remaining Wetlands

Peatlands Remaining Peatlands

Emissions from Managed Peatlands

Managed peatlands are peatlands which have been cleared and drained for the production of peat. The production cycle of a managed peatland has three phases: land conversion in preparation for peat extraction (e.g., draining, and clearing surface biomass), extraction (which results in the emissions reported under *Peatlands Remaining Peatlands*), and abandonment, restoration or conversion of the land to another use.

CO_2 emissions from the removal of biomass and the decay of drained peat constitute the major greenhouse gas flux from managed peatlands. Managed peatlands may also emit CH_4 and N_2O. The natural production of CH_4 is largely reduced but not entirely shut down when peatlands are drained in preparation for peat extraction (Strack et al., 2004 as cited in IPCC 2006); however, CH_4 emissions are assumed to be insignificant under Tier 1 (IPCC, 2006). N_2O emissions from managed peatlands depend on site fertility. In addition, abandoned and restored peatlands continue to release greenhouse gas emissions, and at present no methodology is provided by IPCC (2006) to estimate greenhouse gas emissions or removals from restored peatlands. This inventory estimates both CO_2 and N_2O emissions from *Peatlands Remaining Peatlands* in accordance with Tier 1 IPCC (2006) guidelines.

CO_2 and N_2O Emissions from *Peatlands Remaining Peatlands*

IPCC (2006) recommends reporting CO_2 and N_2O emissions from lands undergoing active peat extraction (i.e., *Peatlands Remaining Peatlands*) as part of the estimate for emissions from managed wetlands. Peatlands occur in wetland areas where plant biomass has sunk to the bottom of water bodies and water-logged areas and exhausted the oxygen supply below the water surface during the course of decay. Due to these anaerobic conditions, much of the plant matter does not decompose but instead forms layers of peat over decades and centuries. In the United States, peat is extracted for horticulture and landscaping growing media, and for a wide variety of industrial, personal care, and other products. It has not been used for fuel in the United States for many decades. Peat is harvested from two types of peat deposits in the United States: sphagnum bogs in northern states and wetlands in states further south. The peat from sphagnum bogs in northern states, which is nutrient poor, is generally corrected for acidity and mixed with fertilizer. Production from more southerly states is relatively coarse (i.e., fibrous) but nutrient rich.

IPCC (2006) recommends considering both on-site and off-site emissions when estimating CO_2 emissions from *Peatlands Remaining Peatlands* using the Tier 1 approach. Current methodologies estimate only on-site N_2O emissions, since off-site N_2O estimates are complicated by the risk of double-counting emissions from nitrogen fertilizers added to horticultural peat. On-site emissions from managed peatlands occur as the land is cleared of vegetation and the underlying peat is exposed to sun and weather. As this occurs, some peat deposit is lost and CO_2 is emitted from the oxidation of the peat. On-site N_2O is emitted during draining depending on site fertility and if the deposit contains significant amounts of organic nitrogen in inactive form. Draining land in preparation for peat extraction allows bacteria to convert the nitrogen into nitrates which leach to the surface where they are reduced to N_2O.

Off-site CO_2 emissions from managed peatlands occur from the horticultural and landscaping use of peat. CO_2 emissions occur as the nutrient-poor (but now fertilizer-enriched) peat is used in bedding plants, other greenhouse and plant nursery production, and by consumers, and as nutrient-rich (but relatively coarse) peat is used directly in landscaping, athletic fields, golf courses, and plant nurseries. Most of the CO_2 emissions from peat occur off-site, as the peat is processed and sold to firms which, in the United States, use it predominately for horticultural purposes. The magnitude of the CO_2 emitted from peat depends on whether the peat has been extracted from nutrient-rich or nutrient-poor peat deposits.

Total emissions from *Peatlands Remaining Peatlands* were estimated to be 1.095 Tg CO_2 Eq. in 2009 (see Table 7-37) comprising 1.090 Tg CO_2 Eq. (1,090 Gg) of CO_2 and 0.005 Tg CO_2 Eq. (0.016 Gg) of N_2O. Total emissions in 2009 were about 10 percent larger than total emissions in 2008, with the increase due to the higher peat production reported in Alaska in 2009.

Total emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO_2 Eq. across the time series with a decreasing trend from 1990 until 1994 followed by an increasing trend through 2000. Since 2000, total emissions show a decreasing trend until 2006 followed by an increasing trend in recent years. CO_2 emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO_2 across the time series and drive the trends in total emissions. N_2O emissions remained close to zero across the time series, with a decreasing trend from 1990 until 1995 followed by an increasing trend through 2000. N_2O emissions decreased between 2000 and 2008, followed by a leveling off in 2009.

Table 7-37: Emissions from *Peatlands Remaining Peatlands* (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	1.0	1.2	1.1	0.9	1.0	1.0	1.1
N_2O	+	+	+	+	+	+	+
Total	**1.0**	**1.2**	**1.1**	**0.9**	**1.0**	**1.0**	**1.1**

+ Less than 0.01 Tg CO_2 Eq.

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Table 7-38: Emissions from *Peatlands Remaining Peatlands* (Gg)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	1,033	1,227	1,079	879	1,012	992	1,090
N_2O	+	+	+	+	+	+	+

+ Less than 0.05 Gg

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Methodology

Off-Site CO_2 Emissions

CO_2 emissions from domestic peat production were estimated using a Tier 1 methodology consistent with IPCC (2006). Off-site CO_2 emissions from *Peatlands Remaining Peatlands* were calculated by apportioning the annual weight of peat produced in the United States (Table 7-39) into peat extracted from nutrient-rich deposits and peat extracted from nutrient-poor deposits using annual percentage by weight figures. These nutrient-rich and nutrient-poor production values were then multiplied by the appropriate default carbon fraction conversion factor taken from IPCC (2006) in order to obtain off-site emission estimates. For the lower 48 states, both annual percentages of peat type by weight and domestic peat production data were sourced from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Commodity Summaries* from the U.S. Geological Survey (USGS 1991–2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying domestic peat producers. The USGS often receives a response to the survey from most of the smaller peat producers, but fewer of the larger ones. For example, of the four active operations producing 23,000 or more metric tons per year, two did not respond to the survey in 2007. As a result, the USGS estimates production from the non-respondent peat producers based on responses to previous surveys (responses from 2004 and 2005, in the case above) or other sources.

The Alaska estimates rely on reported peat production from Alaska's annual Mineral Industry Reports (Szumigala et al. 2010). Similar to the U.S. Geological Survey, Alaska's Mineral Industry Report methodology solicits voluntary reporting of peat production from producers. However, the report does not estimate production for the non-reporting producers, resulting in larger inter-annual variation in reported peat production from Alaska depending on the number of producers who report in a given year (Szumigala 2011). In addition, in both the lower 48 states and Alaska, large variations in peat production can also result from variations in precipitation and the subsequent moisture conditions, since unusually wet years can hamper peat production (USGS 2010). The methodology estimates Alaska emissions separately from lower 48 emissions because the state conducts its own mineral survey and reports peat production by volume, rather than by weight (Table 7-40). However, volume production data was used to calculate off-site CO_2 emissions from Alaska applying the same methodology but with volume-specific carbon fraction conversion factors from IPCC (2006).[193]

The *apparent consumption* of peat, which includes production plus imports minus exports plus the decrease in stockpiles, in the United States is over two-and-a-half times the amount of domestic peat production. Therefore, off-site CO_2 emissions from the use of all horticultural peat within the United States are not accounted for using the Tier 1 approach. The United States has increasingly imported peat from Canada for horticultural purposes; from 2005 to 2008, imports of sphagnum moss (nutrient-poor) peat from Canada represented 97 percent of total U.S. peat imports (USGS 2010). Most peat produced in the United States is reed-sedge peat, generally from southern states, which is classified as nutrient rich by IPCC (2006). Higher-tier calculations of CO_2 emissions from apparent consumption would involve consideration of the percentages of peat types stockpiled (nutrient rich versus nutrient poor) as well as the percentages of peat types imported and exported.

Table 7-39: Peat Production of Lower 48 States (in thousands of Metric Tons)

Type of Deposit	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Nutrient-Rich	595.1		728.6		657.6	529.0	581.0	559.7	554.2
Nutrient-Poor	55.4		63.4		27.4	22.0	54.0	55.4	54.8
Total Production	**692.0**		**792.0**		**685.0**	**551.0**	**635.0**	**615.0**	**609.0**

Sources: *Minerals Yearbook: Peat* (1990–2008 Reports), *Mineral Commodity Summaries: Peat* (1996–2009 Reports), and Apodaca (2010). United States Geological Survey.

Table 7-40: Peat Production of Alaska (in thousands of Cubic Meters)

	1990		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**
Total Production	**49.7**		**27.2**		**47.8**	**50.8**	**52.3**	**64.1**	**183.9**

Sources: *Alaska's Mineral Industry* (1992–2009) Reports. Division of Geological & Geophysical Surveys, Alaska Department of Natural Resources.

On-site CO_2 Emissions

IPCC (2006) suggests basing the calculation of on-site emissions estimates on the area of peatlands managed for peat extraction differentiated by the nutrient type of the deposit (rich versus poor). Information on the area of land managed for peat extraction is currently not available for the United States, but in accordance with IPCC (2006), an average production rate for the industry was applied to derive an area estimate. In a mature industrialized peat industry, such as exists in the United States and Canada, the vacuum method[194] can extract up to 100 metric ton per hectare per year (Cleary et al. 2005 as cited in IPCC 2006). The area of land managed for peat extraction in the United States was estimated using nutrient-rich and nutrient-poor production data and the assumption that 100 metric tons of peat are extracted from a single hectare in a single year. The annual land area estimates were then multiplied by the appropriate nutrient-rich or nutrient-poor IPCC (2006) default emission factor in order to calculate on-site CO_2 emission estimates. Production data are not available by weight for Alaska. In order to calculate on-site emissions resulting from *Peatlands Remaining Peatlands* in Alaska, the production data by volume were converted to weight using annual average bulk peat density values, and then converted to land area estimates using the same assumption that a single hectare yields 100 metric tons. The IPCC (2006) on-site emissions equation also includes a term which accounts for emissions resulting from the change in carbon stocks that occurs during the clearing of vegetation prior to peat extraction. Area data on land undergoing conversion to peatlands for peat extraction is also unavailable for the United States. However, USGS records show that the number of active operations in the United

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[193] Peat produced from Alaska was assumed to be nutrient poor; as is the case in Canada, "where deposits of high-quality [but nutrient poor] sphagnum moss are extensive" (USGS 2008).

[194] The vacuum method is one type of extraction that annually "mills" or breaks up the surface of the peat into particles, which then dry during the summer months. The air-dried peat particles are then collected by vacuum harvesters and transported from the area to stockpiles (IPCC 2006).

States has been declining since 1990; therefore it seems reasonable to assume that no new areas are being cleared of vegetation for managed peat extraction. Other changes in carbon stocks in living biomass on managed peatlands are also assumed to be zero under the Tier 1 methodology (IPCC 2006).

On-site N_2O Emissions

IPCC (2006) suggests basing the calculation of on-site N_2O emissions estimates on the area of nutrient-rich peatlands managed for peat extraction. These area data are not available directly for the United States, but the on-site CO_2 emissions methodology above details the calculation of area data from production data. In order to estimate N_2O emissions, the area of nutrient rich *Peatlands Remaining Peatlands* was multiplied by the appropriate default emission factor taken from IPCC (2006).

Uncertainty

The uncertainty associated with peat production data was estimated to be ± 25 percent (Apodaca 2008) and assumed to be normally distributed. The uncertainty associated with peat production data stems from the fact that the USGS receives data from the smaller peat producers but estimates production from some larger peat distributors. This same uncertainty and distribution was assumed for the peat type production percentages. The uncertainty associated with the Alaskan reported production data was assumed to be the same as the lower 48 states, or ± 25 percent with a normal distribution. It should be noted that the Alaskan Department of Natural Resources estimate that around half of producers do not respond to their survey with peat production data; therefore, the production numbers reported are likely to underestimate Alaska peat production (Szumigala 2008). The uncertainty associated with the average bulk density values was estimated to be ± 25 percent with a normal distribution (Apodaca 2008). IPCC (2006) gives uncertainty values for the emissions factors for the area of peat deposits managed for peat extraction based on the range of underlying data used to determine the emissions factors. The uncertainty associated with the emission factors was assumed to be triangularly distributed. The uncertainty values surrounding the carbon fractions were based on IPCC (2006) and the uncertainty was assumed to be uniformly distributed. Based on these values and distributions, a Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-41. CO_2 emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.8 and 1.5 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 30 percent below to 34 percent above the 2009 emission estimate of 1.1 Tg CO_2 Eq. N_2O emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.001 and 0.007 Tg CO_2 Eq. at the 95 percent confidence level. This indicates a range of 74 percent below to 41 percent above the 2009 emission estimate of 0.005 Tg CO_2 Eq.

Table 7-41: Tier-2 Quantitative Uncertainty Estimates for CO_2 Emissions from *Peatlands Remaining Peatlands*

Source	**Gas**	**2009 Emissions Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emissions Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Peatlands Remaining Peatlands	CO_2	1.1	0.8	1.5	-30%	34%
	N_2O	+	+	+	-74%	41%

+ Does not exceed 0.01 Tg CO_2 Eq. or 0.5 Gg.

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

The current Inventory represents the third Inventory report in which emissions from *Peatlands Remaining Peatlands* are included . A revised 2008 estimate of peat production by volume for Alaska was reported in 2010 (Szumigala et al. 2010). Updating the 2008 production data with this revised estimate led to a 5 percent increase over the previous 2008 emission estimate.

Planned Improvements

In order to further improve estimates of CO_2 and N_2O emissions from *Peatlands Remaining Peatlands*, future efforts will consider options for obtaining better data on the quantity of peat harvested per hectare and the total area undergoing peat extraction.

7.9. *Settlements Remaining Settlements*

Changes in Carbon Stocks in Urban Trees (IPCC Source Category 5E1)

Urban forests constitute a significant portion of the total U.S. tree canopy cover (Dwyer et al. 2000). Urban areas (cities, towns, and villages) are estimated to cover over 4 percent of the United States (Nowak et al. 2005). With an average tree canopy cover of 27 percent, urban areas account for approximately 3 percent of total tree cover in the continental United States (Nowak et al. 2001). Trees in urban areas of the United States were estimated to account for an average annual net sequestration of 76.5 Tg CO_2 Eq. (20.9 Tg C) over the period from 1990 through 2009. Net C flux from urban trees in 2009 was estimated to be -95.9 Tg CO_2 Eq. (-26.2 Tg C). Annual estimates of CO_2 flux (Table 7-42) were developed based on periodic (1990 and 2000) U.S. Census data on urbanized area. This estimated urban area is smaller than the area categorized as *Settlements* in the Representation of the U.S. Land Base developed for this report, by an average of 21 percent over the 1990 through 2009 time series—i.e., the Census urban area is a subset of the *Settlements* area. Census area data are preferentially used to develop C flux estimates for this source category since these data are more applicable for use with the available peer-reviewed data on urban tree canopy cover and urban tree C sequestration. Annual sequestration increased by 68 percent between 1990 and 2009 due to increases in urban land area. Data on C storage and urban tree coverage were collected since the early 1990s and have been applied to the entire time series in this report.

Net C flux from urban trees is proportionately greater on an area basis than that of forests. This trend is primarily the result of different net growth rates in urban areas versus forests—urban trees often grow faster than forest trees because of the relatively open structure of the urban forest (Nowak and Crane 2002). However, areas in each case are accounted for differently. Because urban areas contain less tree coverage than forest areas, the C storage per hectare of land is in fact smaller for urban areas. However, urban tree reporting occurs on a basis of C sequestered per unit area of tree cover, rather than C sequestered per total land area. Areas covered by urban trees, therefore, appear to have a greater C density than do forested areas (Nowak and Crane 2002).

Table 7-42: Net C Flux from Urban Trees (Tg CO_2 Eq. and Tg C)

Year	**Tg CO_2 Eq.**	**Tg C**
1990	(57.1)	(15.6)
2000	(77.5)	(21.1)
2005	(87.8)	(23.9)
2006	(89.8)	(24.5)
2007	(91.9)	(25.1)
2008	(93.9)	(25.6)
2009	(95.9)	(26.2)

Note: Parentheses indicate net sequestration.

Methodology

Methods for quantifying urban tree biomass, C sequestration, and C emissions from tree mortality and decomposition were taken directly from Nowak and Crane (2002) and Nowak (1994). In general, the methodology used by Nowak and Crane (2002) to estimate net C sequestration in urban trees followed three steps. First, field data from 14 cities were used to generate allometric estimates of biomass from measured tree dimensions. Second, estimates of tree growth and biomass increment were generated from published literature and adjusted for tree condition and land-use class to generate estimates of gross C sequestration in urban trees. Third, estimates of C emissions due to mortality and decomposition were subtracted from gross C sequestration values to derive estimates of net C sequestration. Sequestration estimates for these cities, in units of carbon sequestered per unit area of tree cover, were then used to estimate urban forest C sequestration in the U.S. by using urban area estimates from U.S. Census data and urban tree cover estimates from remote sensing data, an approach consistent with Nowak and Crane (2002).

This approach is also consistent with the default IPCC methodology in IPCC (2006), although sufficient data are not yet available to separately determine interannual gains and losses in C stocks in the living biomass of urban trees. Annual changes in net C flux from urban trees are based solely on changes in total urban area in the United States.

In order to generate the allometric relationships between tree dimensions and tree biomass, Nowak and Crane (2002) and Nowak (1994, 2007c, 2009) collected field measurements in a number of U.S. cities between 1989 and 2002. For a sample of trees in each of the cities in Table 7-43, data including tree measurements of stem diameter, tree height, crown height and crown width, and information on location, species, and canopy condition were collected. The data for each tree were converted into C storage by applying allometric equations to estimate aboveground biomass, a root-to-shoot ratio to convert aboveground biomass estimates to whole tree biomass, moisture content, a C content of 50 percent (dry weight basis), and an adjustment factor of 0.8 to account for urban trees having less aboveground biomass for a given stem diameter than predicted by allometric equations based on forest trees (Nowak 1994). C storage estimates for deciduous trees include only carbon stored in wood. These calculations were then used to develop an allometric equation relating tree dimensions to C storage for each species of tree, encompassing a range of diameters.

Tree growth was estimated using annual height growth and diameter growth rates for specific land uses and diameter classes. Growth calculations were adjusted by a factor to account for tree condition (fair to excellent, poor, critical, dying, or dead). For each tree, the difference in C storage estimates between year 1 and year (x + 1) represents the gross amount of C sequestered. These annual gross C sequestration rates for each species (or genus), diameter class, and land-use condition (e.g., parks, transportation, vacant, golf courses) were then scaled up to city estimates using tree population information. The area of assessment for each city was defined by its political boundaries; parks and other forested urban areas were thus included in sequestration estimates (Nowak 2011).

Most of the field data used to develop the methodology of Nowak et al. were analyzed using the U.S. Forest Service's Urban Forest Effects (UFORE) model. UFORE is a computer model that uses standardized field data from random plots in each city and local air pollution and meteorological data to quantify urban forest structure, values of the urban forest, and environmental effects, including total C stored and annual C sequestration. UFORE was used with field data from a stratified random sample of plots in each city to quantify the characteristics of the urban forest. (Nowak et al. 2007a).

Gross C emissions result from tree death and removals. Estimates of gross C emissions from urban trees were derived by applying estimates of annual mortality and condition, and assumptions about whether dead trees were removed from the site to the total C stock estimate for each city. Estimates of annual mortality rates by diameter class and condition class were derived from a study of street-tree mortality (Nowak 1986). Different decomposition rates were applied to dead trees left standing compared with those removed from the site. For removed trees, different rates were applied to the removed/aboveground biomass in contrast to the belowground biomass. The estimated annual gross C emission rates for each species (or genus), diameter class, and condition class were then scaled up to city estimates using tree population information.

The field data for 13 of the 14 cities are described in Nowak and Crane (2002), Nowak et al. (2007a), and references cited therein. Data for the remaining city, Chicago, were taken from unpublished results (Nowak 2009). The allometric equations applied to the field data for each tree were taken from the scientific literature (see Nowak 1994, Nowak et al. 2002), but if no allometric equation could be found for the particular species, the average result for the genus was used. The adjustment (0.8) to account for less live tree biomass in urban trees was based on information in Nowak (1994). A root-to-shoot ratio of 0.26 was taken from Cairns et al. (1997), and species- or genus-specific moisture contents were taken from various literature sources (see Nowak 1994). Tree growth rates were taken from existing literature. Average diameter growth was based on the following sources: estimates for trees in forest stands came from Smith and Shifley (1984); estimates for trees on land uses with a park-like structure came from deVries (1987); and estimates for more open-grown trees came from Nowak (1994). Formulas from Fleming (1988) formed the basis for average height growth calculations. As described above, growth rates were adjusted to account for tree condition. Growth factors for Atlanta, Boston, Freehold, Jersey City, Moorestown, New York, Philadelphia, and Woodbridge were adjusted based on the typical growth conditions of different land-use categories (e.g., forest stands, park-like stands). Growth factors for the more recent studies in Baltimore, Chicago, Minneapolis, San

Francisco, Syracuse, and Washington were adjusted using an updated methodology based on the condition of each individual tree, which is determined using tree competition factors (depending on whether it is open grown or suppressed) (Nowak 2007b). Assumptions for which dead trees would be removed versus left standing were developed specific to each land use and were based on expert judgment of the authors. Decomposition rates were based on literature estimates (Nowak and Crane 2002).

Estimates of gross and net sequestration rates for each of the 14 cities (Table 7-43) were compiled in units of C sequestration per unit area of tree canopy cover. These rates were used in conjunction with estimates of national urban area and urban tree cover data to calculate national annual net C sequestration by urban trees for the United States. This method was described in Nowak and Crane (2002) and has been modified to incorporate U.S. Census data.

Specifically, urban area estimates were based on 1990 and 2000 U.S. Census data. The 1990 U.S. Census defined urban land as “urbanized areas,” which included land with a population density greater than 1,000 people per square mile, and adjacent “urban places,” which had predefined political boundaries and a population total greater than 2,500. In 2000, the U.S. Census replaced the “urban places” category with a new category of urban land called an “urban cluster,” which included areas with more than 500 people per square mile. Urban land area increased by approximately 36 percent from 1990 to 2000; Nowak et al. (2005) estimate that the changes in the definition of urban land are responsible for approximately 20 percent of the total reported increase in urban land area from 1990 to 2000. Under both 1990 and 2000 definitions, the urban category encompasses most cities, towns, and villages (i.e., it includes both urban and suburban areas).

Settlements area, as assessed in the Representation of the U.S. Land Base developed for this report, encompassed all developed parcels greater than 0.1 hectares in size, including rural transportation corridors, and as previously mentioned represent a larger area than the Census-derived urban area estimates. However, the Census-derived urban area estimates were deemed to be more suitable for estimating national urban tree cover given the data available in the peer-reviewed literature. Specifically, tree canopy cover of U.S. urban areas was estimated by Nowak et al. (2001) to be 27 percent, assessed across Census-delineated urbanized areas, urban places, and places containing urbanized area. This canopy cover percentage is multiplied by the urban area estimated for each year to produce an estimate of national urban tree cover area.

Net annual C sequestration estimates were derived for the 14 cities by subtracting the gross annual emission estimates from the gross annual sequestration estimates. The gross and net annual C sequestration values for each city were divided by each city’s area of tree cover to determine the average annual sequestration rates per unit of tree area for each city. The median value for gross sequestration per unit area of tree cover (0.29 kg C/m^2-yr) was then multiplied by the estimate of national urban tree cover area to estimate national annual gross sequestration, per the methods of Nowak and Crane (2002). To estimate national annual net sequestration, the estimate of national annual gross sequestration was multiplied by the average of the ratios of net to gross sequestration (0.72) for those cities that had both estimates. The urban tree cover estimates for each of the 14 cities and the United States were obtained from Dwyer et al. (2000), Nowak et al. (2002), Nowak (2007a), and Nowak (2009). The urban area estimates were taken from Nowak et al. (2005).

Table 7-43: C Stocks (Metric Tons C), Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m^2-yr) for 14 U.S. Cities

City	Carbon Stocks	Gross Annual Sequestration	Net Annual Sequestration	Tree Cover	Gross Annual Sequestration per Area of Tree Cover	Net Annual Sequestration per Area of Tree Cover	Net:Gross Annual Sequestration Ratio
Atlanta, GA	1,219,256	42,093	32,169	36.7%	0.34	0.26	0.76
Baltimore, MD	541,589	14,696	9,261	21.0%	0.35	0.22	0.63
Boston, MA	289,392	9,525	6,966	22.3%	0.30	0.22	0.73
Chicago, IL	649,000	22,800	16,100	17.2%	0.22	0.16	0.71
Freehold, NJ	18,144	494	318	34.4%	0.28	0.18	0.64
Jersey City, NJ	19,051	807	577	11.5%	0.18	0.13	0.71
Minneapolis, MN	226,796	8,074	4,265	26.4%	0.20	0.11	0.53
Moorestown, NJ	106,141	3,411	2,577	28.0%	0.32	0.24	0.76
New York, NY	1,224,699	38,374	20,786	20.9%	0.23	0.12	0.54
Philadelphia, PA	480,808	14,606	10,530	15.7%	0.27	0.20	0.72

San Francisco, CA	175,994	4,627	4,152	11.9%	0.33	0.29	0.90
Syracuse, NY	156,943	4,917	4,270	23.1%	0.33	0.29	0.87
Washington, DC	477,179	14,696	11,661	28.6%	0.32	0.26	0.79
Woodbridge, NJ	145,150	5,044	3,663	29.5%	0.28	0.21	0.73
					Median: 0.29		**Mean:** 0.72

NA = not analyzed.
Sources: Nowak and Crane (2002), Nowak (2007a,c), and Nowak (2009).

Uncertainty and Time-Series Consistency

Uncertainty associated with changes in C stocks in urban trees includes the uncertainty associated with urban area, percent urban tree coverage, and estimates of gross and net C sequestration for each of the 14 U.S. cities. A 10 percent uncertainty was associated with urban area estimates while a 5 percent uncertainty was associated with percent urban tree coverage. Both of these uncertainty estimates were based on expert judgment. Uncertainty associated with estimates of gross and net C sequestration for each of the 14 U.S. cities was based on standard error estimates for each of the city-level sequestration estimates reported by Nowak (2007c) and Nowak (2009). These estimates are based on field data collected in each of the 14 U.S. cities, and uncertainty in these estimates increases as they are scaled up to the national level.

Additional uncertainty is associated with the biomass equations, conversion factors, and decomposition assumptions used to calculate C sequestration and emission estimates (Nowak et al. 2002). These results also exclude changes in soil C stocks, and there may be some overlap between the urban tree C estimates and the forest tree C estimates. Due to data limitations, urban soil flux is not quantified as part of this analysis, while reconciliation of urban tree and forest tree estimates will be addressed through the land-representation effort described in the Planned Improvements section of this chapter.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-44. The net C flux from changes in C stocks in urban trees in 2009 was estimated to be between -116.8 and -77.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below and 19 percent above the 2009 flux estimate of -95.9 Tg CO_2 Eq.

Table 7-44: Tier 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Changes in C Stocks in Urban Trees	CO_2	(95.9)	(116.8)	(77.7)	−22%	+19%

Note: Parentheses indicate negative values or net sequestration.

Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

The net C flux resulting from urban trees was predominately calculated using estimates of gross and net C sequestration estimates for urban trees and urban tree coverage area published in the literature. The validity of these data for their use in this section of the inventory was evaluated through correspondence established with an author of the papers. Through this correspondence, the methods used to collect the urban tree sequestration and area data were further clarified and the use of these data in the inventory was reviewed and validated (Nowak 2002a, 2007b, 2011).

Planned Improvements

A consistent representation of the managed land base in the United States is being developed. A component of this effort, which is discussed at the beginning of the Land Use, Land-Use Change, and Forestry chapter, will involve reconciling the overlap between urban forest and non-urban forest greenhouse gas inventories. It is highly likely that urban forest inventories are including areas also defined as forest land under the Forest Inventory and Analysis (FIA) program of the USDA Forest Service, resulting in “double-counting” of these land areas in estimates of C stocks and fluxes for the inventory. The Forest Service is currently conducting research that will define urban area boundaries and make it possible to distinguish forest from forested urban areas. Once those data become available, they will be incorporated into estimates of net C flux resulting from urban trees.

Urban forest data for additional cities are expected in the near future, as are updated data for cities currently included in the estimates. The use of these data will further refine the estimated median sequestration value. It may also be possible to report C losses and gains separately in the future. It is currently not possible, since existing studies estimate rather than measure natality or mortality; net sequestration estimates are based on assumptions about whether dead trees are being removed, burned, or chipped. There is an effort underway to assess urban tree loss to mortality and removals, which would allow for direct calculation of C losses and gains from observed rather than estimated natality and mortality of trees.

Data from the 2010 U.S. Census is expected to provide updated U.S. urbanized area, which would allow for refinement of the urban area time series. Revisions to urban area time series will result in revisions to prior years’ C flux estimates.

A revised average tree canopy cover percentage for U.S. urban areas is anticipated to become available in the peer-reviewed literature in the near future, which would allow for updated C flux estimates. Furthermore, urban tree cover data specific to each state is also expected in the near future. It may be possible to develop a set of state-specific sequestration rates for more granular and regionally precise C flux estimates by coupling these data with adjusted growth rates for each U.S. state. Future research may also enable more complete coverage of changes in the C stock in urban trees for all *Settlements* land. To provide estimates for all *Settlements*, research would need to establish the extent of overlap between *Settlements* and Census-defined urban areas, and would have to characterize sequestration on non-urban *Settlements* land.

Direct N_2O Fluxes from Settlement Soils (IPCC Source Category 5E1)

Of the synthetic N fertilizers applied to soils in the United States, approximately 2.5 percent are currently applied to lawns, golf courses, and other landscaping occurring within settlement areas. Application rates are lower than those occurring on cropped soils, and, therefore, account for a smaller proportion of total U.S. soil N_2O emissions per unit area. In addition to synthetic N fertilizers, a portion of surface applied sewage sludge is applied to settlement areas. In 2009, N_2O emissions from this source were 1.5 Tg CO_2 Eq. (4.9 Gg). There was an overall increase of 55 percent over the period from 1990 through 2009 due to a general increase in the application of synthetic N fertilizers to an expanding settlement area. Interannual variability in these emissions is directly attributable to interannual variability in total synthetic fertilizer consumption and sewage sludge applications in the United States. Emissions from this source are summarized in Table 7-45.

Table 7-45: Direct N_2O Fluxes from Soils in *Settlements Remaining Settlements* (Tg CO_2 Eq. and Gg N_2O)

Year	Tg CO_2 Eq.	Gg
1990	1.0	3.2
2000	1.1	3.7
2005	1.5	4.7
2006	1.5	4.8
2007	1.6	5.1
2008	1.5	4.9
2009	1.5	4.9

Note: These estimates include direct N_2O emissions from N fertilizer additions only. Indirect N_2O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

Methodology

For soils within *Settlements Remaining Settlements*, the IPCC Tier 1 approach was used to estimate soil N_2O emissions from synthetic N fertilizer and sewage sludge additions. Estimates of direct N_2O emissions from soils in settlements were based on the amount of N in synthetic commercial fertilizers applied to settlement soils, and the amount of N in sewage sludge applied to non-agricultural land and surface disposal of sewage sludge (see Annex 3.11 for a detailed discussion of the methodology for estimating sewage sludge application).

Nitrogen applications to settlement soils are estimated using data compiled by the USGS (Ruddy et al. 2006). The USGS estimated on-farm and non-farm fertilizer use is based on sales records at the county level from 1982 through 2001 (Ruddy et al. 2006). Non-farm N fertilizer was assumed to be applied to settlements and forest lands; values for 2002 through 2008 were based on 2001 values adjusted for annual total N fertilizer sales in the United States because there is no new activity data on application after 2001. Settlement application was calculated by subtracting forest application from total non-farm fertilizer use. Sewage sludge applications were derived from national data on sewage sludge generation, disposition, and N content (see Annex 3.11 for further detail). The total amount of N resulting from these sources was multiplied by the IPCC default emission factor for applied N (1 percent) to estimate direct N_2O emissions (IPCC 2006). The volatilized and leached/runoff N fractions for settlements, calculated with the IPCC default volatilization factors (10 or 20 percent, respectively, for synthetic or organic N fertilizers) and leaching/runoff factor for wet areas (30 percent), were included with indirect emissions, as reported in the N_2O Emissions from Agricultural Soil Management source category of the Agriculture chapter (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N_2O emitted from settlements depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and irrigation/watering practices. The effect of the combined interaction of these variables on N_2O flux is complex and highly uncertain. The IPCC default methodology does not explicitly incorporate any of these variables, except variations in fertilizer N and sewage sludge application rates. All settlement soils are treated equivalently under this methodology.

Uncertainties exist in both the fertilizer N and sewage sludge application rates in addition to the emission factors. Uncertainty in fertilizer N application was assigned a default level[195] of ±50 percent. Uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal was derived from variability in several factors, including: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996 and 2000; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal. Uncertainty in the emission factors was provided by the IPCC (2006).

Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emission estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-46. N_2O emissions from soils in Settlements Remaining Settlements in 2009 were estimated to be between 0.8 and 4.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 49 percent below to 163 percent above the 2009 emission estimate of 1.5 Tg CO_2 Eq.

Table 7-46: Quantitative Uncertainty Estimates of N_2O Emissions from Soils in *Settlements Remaining Settlements* (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emissions (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Emission Estimate**			
			(Tg CO_2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Settlements Remaining Settlements:						
N_2O Fluxes from Soils	N_2O	1.5	0.8	4.0	-49%	163%

Note: This estimate includes direct N_2O emissions from N fertilizer additions to both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

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[195] No uncertainty is provided with the USGS application data (Ruddy et al. 2006) so a conservative ±50% was used in the analysis.

Planned Improvements

A minor improvement is planned to update the uncertainty analysis for direct emissions from settlements to be consistent with the most recent activity data for this source.

7.10. Land Converted to Settlements (Source Category 5E2)

Land-use change is constantly occurring, and land under a number of uses undergoes urbanization in the United States each year. However, data on the amount of land converted to settlements is currently lacking. Given the lack of available information relevant to this particular IPCC source category, it is not possible to separate CO_2 or N_2O fluxes on *Land Converted to Settlements* from fluxes on *Settlements Remaining Settlements* at this time.

7.11. Other (IPCC Source Category 5G)

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

In the United States, a significant change in C stocks results from the removal of yard trimmings (i.e., grass clippings, leaves, and branches) and food scraps from settlements to be disposed in landfills. Yard trimmings and food scraps account for a significant portion of the municipal waste stream, and a large fraction of the collected yard trimmings and food scraps are discarded in landfills. C contained in landfilled yard trimmings and food scraps can be stored for very long periods.

Carbon storage estimates are associated with particular land uses. For example, harvested wood products are accounted for under *Forest Land Remaining Forest Land* because these wood products are a component of the forest ecosystem. The wood products serve as reservoirs to which C resulting from photosynthesis in trees is transferred, but the removals in this case occur in the forest. C stock changes in yard trimmings and food scraps are associated with settlements, but removals in this case do not occur within settlements. To address this complexity, yard trimming and food scrap C storage is therefore reported under the “Other” source category.

Both the amount of yard trimmings collected annually and the fraction that is landfilled have declined over the last decade. In 1990, over 53 million metric tons (wet weight) of yard trimmings and food scraps were generated (i.e., put at the curb for collection to be taken to disposal sites or to composting facilities) (EPA 2011; Schneider 2007, 2008). Since then, programs banning or discouraging yard trimmings disposal have led to an increase in backyard composting and the use of mulching mowers, and a consequent 5 percent decrease in the tonnage generated (i.e., collected for composting or disposal). At the same time, an increase in the number of municipal composting facilities has reduced the proportion of collected yard trimmings that are discarded in landfills—from 72 percent in 1990 to 33 percent in 2009. The net effect of the reduction in generation and the increase in composting is a 57 percent decrease in the quantity of yard trimmings disposed in landfills since 1990.

Food scraps generation has grown by 44 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 80 percent in 2009, the tonnage disposed in landfills has increased considerably (by 40 percent). Overall, the decrease in the yard trimmings landfill disposal rate has more than compensated for the increase in food scrap disposal in landfills, and the net result is a decrease in annual landfill carbon storage from 24.2 Tg CO_2 Eq. in 1990 to 12.6 Tg CO_2 Eq. in 2009 (Table 7-47 and Table 7-48).

Table 7-47: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg CO_2 Eq.)

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Yard Trimmings	**(21.0)**	**(8.8)**	**(7.3)**	**(7.5)**	**(7.0)**	**(7.3)**	**(8.5)**
Grass	(1.8)	(0.7)	(0.6)	(0.6)	(0.6)	(0.7)	(0.8)
Leaves	(9.0)	(3.9)	(3.3)	(3.4)	(3.2)	(3.4)	(3.9)
Branches	(10.2)	(4.2)	(3.3)	(3.4)	(3.2)	(3.3)	(3.8)
Food Scraps	**(3.2)**	**(4.4)**	**(4.3)**	**(3.5)**	**(3.9)**	**(3.9)**	**(4.1)**
Total Net Flux	**(24.2)**	**(13.2)**	**(11.5)**	**(11.0)**	**(10.9)**	**(11.2)**	**(12.6)**

Note: Totals may not sum due to independent rounding.

Table 7-48: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg C)

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Yard Trimmings	**(5.7)**	**(2.4)**	**(2.0)**	**(2.0)**	**(1.9)**	**(2.0)**	**(2.3)**
Grass	(0.5)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Leaves	(2.5)	(1.1)	(0.9)	(0.9)	(0.9)	(0.9)	(1.1)
Branches	(2.8)	(1.2)	(0.9)	(0.9)	(0.9)	(0.9)	(1.0)
Food Scraps	**(0.9)**	**(1.2)**	**(1.2)**	**(1.0)**	**(1.1)**	**(1.1)**	**(1.1)**
Total Net Flux	**(6.6)**	**(3.6)**	**(3.1)**	**(3.0)**	**(3.0)**	**(3.1)**	**(3.4)**

Note: Totals may not sum due to independent rounding.

Methodology

When wastes of biogenic origin (such as yard trimmings and food scraps) are landfilled and do not completely decompose, the C that remains is effectively removed from the global C cycle. Empirical evidence indicates that yard trimmings and food scraps do not completely decompose in landfills (Barlaz 1998, 2005, 2008; De la Cruz and Barlaz 2010), and thus the stock of carbon in landfills can increase, with the net effect being a net atmospheric removal of carbon. Estimates of net C flux resulting from landfilled yard trimmings and food scraps were developed by estimating the change in landfilled C stocks between inventory years, based on methodologies presented for the Land Use, Land-Use Change, and Forestry sector in IPCC (2003). C stock estimates were calculated by determining the mass of landfilled C resulting from yard trimmings or food scraps discarded in a given year; adding the accumulated landfilled C from previous years; and subtracting the mass of C landfilled in previous years that decomposed.

To determine the total landfilled C stocks for a given year, the following were estimated: (1) the composition of the yard trimmings; (2) the mass of yard trimmings and food scraps discarded in landfills; (3) the C storage factor of the landfilled yard trimmings and food scraps; and (4) the rate of decomposition of the degradable C. The composition of yard trimmings was assumed to be 30 percent grass clippings, 40 percent leaves, and 30 percent branches on a wet weight basis (Oshins and Block 2000). The yard trimmings were subdivided, because each component has its own unique adjusted C storage factor and rate of decomposition. The mass of yard trimmings and food scraps disposed of in landfills was estimated by multiplying the quantity of yard trimmings and food scraps discarded by the proportion of discards managed in landfills. Data on discards (i.e., the amount generated minus the amount diverted to centralized composting facilities) for both yard trimmings and food scraps were taken primarily from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011), which provides data for 1960, 1970, 1980, 1990, 2000, and 2005 through 2009. To provide data for some of the missing years, detailed backup data were obtained from Schneider (2007, 2008). Remaining years in the time series for which data were not provided were estimated using linear interpolation. The EPA (2011) report does not subdivide discards of individual materials into volumes landfilled and combusted, although it provides an estimate of the proportion of overall waste stream discards managed in landfills[196] and combustors with energy recovery (i.e., ranging from 100 percent and 0 percent, respectively, in 1960 to 81 percent and 19 percent in 2000); it is assumed that the proportion of each individual material (food scraps, grass, leaves, branches) that is landfilled is the same as the proportion across the overall waste stream.

The amount of C disposed of in landfills each year, starting in 1960, was estimated by converting the discarded landfilled yard trimmings and food scraps from a wet weight to a dry weight basis, and then multiplying by the initial (i.e., pre-decomposition) C content (as a fraction of dry weight). The dry weight of landfilled material was calculated using dry weight to wet weight ratios (Tchobanoglous et al. 1993, cited by Barlaz 1998) and the initial C contents and the C storage factors were determined by Barlaz (1998, 2005, 2008) (Table 7-49).

The amount of C remaining in the landfill for each subsequent year was tracked based on a simple model of C fate. As demonstrated by Barlaz (1998, 2005, 2008), a portion of the initial C resists decomposition and is essentially persistent in the landfill environment. Barlaz (1998, 2005, 2008) conducted a series of experiments designed to

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[196] EPA (2011) reports discards in two categories: "combustion with energy recovery" and "landfill, other disposal," which includes combustion without energy recovery. For years in which there is data from previous EPA reports on combustion without energy recovery, EPA assumes these estimates are still applicable. For 2000 to present, EPA assumes that any combustion of MSW that occurs includes energy recovery, so all discards to "landfill, other disposal" are assumed to go to landfills.

measure biodegradation of yard trimmings, food scraps, and other materials, in conditions designed to promote decomposition (i.e., by providing ample moisture and nutrients). After measuring the initial C content, the materials were placed in sealed containers along with a "seed" containing methanogenic microbes from a landfill. Once decomposition was complete, the yard trimmings and food scraps were re-analyzed for C content; the C remaining in the solid sample can be expressed as a proportion of initial C (shown in the row labeled "CS" in Table 7-49).

The modeling approach applied to simulate U.S. landfill C flows builds on the findings of Barlaz (1998, 2005, 2008). The proportion of C stored is assumed to persist in landfills. The remaining portion is assumed to degrade, resulting in emissions of CH_4 and CO_2 (the CH_4 emissions resulting from decomposition of yard trimmings and food scraps are accounted for in the "Waste" chapter). The degradable portion of the C is assumed to decay according to first-order kinetics.

The first-order decay rates, *k*, for each component were derived from De la Cruz and Barlaz (2010). De la Cruz and Barlaz (2010) calculate first-order decay rates using laboratory data published in Eleazer et al. (1997), and a correction factor, *f*, is found so that the weighted average decay rate for all components is equal to the AP-42 default decay rate (0.04) for mixed MSW for regions that receive more than 25 inches of rain annually. Because AP-42 values were developed using landfill data from approximately 1990, 1990 waste composition for the United States from EPA's *Characterization of Municipal Solid Waste in the United States: 1990 Update* was used to calculate *f*. This correction factor is then multiplied by the Eleazer et al. (1997) decay rates of each waste component to develop field-scale first-order decay rates.

De la Cruz and Barlaz (2010) also use other assumed initial decay rates for mixed MSW in place of the AP-42 default value based on different types of environments in which landfills in the United States are found, including dry conditions (less than 25 inches of rain annually, k=0.02) and bioreactor landfill conditions (moisture is controlled for rapid decomposition, k=0.12). The *Landfills* section of the Inventory (which estimates CH_4 emissions) estimates the overall MSW decay rate by partitioning the U.S. landfill population into three categories, based on annual precipitation ranges of (1) less than 20 inches of rain per year, (2) 20 to 40 inches of rain per year, and (3) greater than 40 inches of rain per year. These correspond to overall MSW decay rates of 0.020, 0.038, and 0.057 yr^{-1}, respectively.

De la Cruz and Barlaz (2010) calculate component-specific decay rates corresponding to the first value (0.020 yr^{-1}), but not for the other two overall MSW decay rates. To maintain consistency between landfill methodologies across the Inventory, the correction factors (*f*) were developed for decay rates of 0.038 and 0.057 yr^{-1} through linear interpolation. A weighted national average component-specific decay rate was calculated by assuming that waste generation is proportional to population (the same assumption used in the landfill methane emission estimate), based on population data from the 2000 U.S. Census. The component-specific decay rates are shown in Table 7-49.

For each of the four materials (grass, leaves, branches, food scraps), the stock of C in landfills for any given year is calculated according to the following formula:

$$LFC_{i,t} = \sum_{n}^{t} W_{i,n} \times (1 - MC_i) \times ICC_i \times \{[CS_i \times ICC_i] + [(1 - (CS_i \times ICC_i)) \times e^{-k(t-n)}]\}$$

where,

t = Year for which C stocks are being estimated (year),
i = Waste type for which C stocks are being estimated (grass, leaves, branches, food scraps),
$LFC_{i,t}$ = Stock of C in landfills in year *t*, for waste *i* (metric tons),
$W_{i,n}$ = Mass of waste *i* disposed in landfills in year *n* (metric tons, wet weight),
n = Year in which the waste was disposed (year, where $1960 < n < t$),
MC_i = Moisture content of waste *i* (percent of water),
CS_i = Proportion of initial C that is stored for waste *i* (percent),
ICC_i = Initial C content of waste *i* (percent),
e = Natural logarithm, and
k = First-order decay rate for waste *i*, ($year^{-1}$).

For a given year *t*, the total stock of C in landfills ($TLFC_t$) is the sum of stocks across all four materials (grass, leaves, branches, food scraps). The annual flux of C in landfills (F_t) for year *t* is calculated as the change in stock compared to the preceding year:

$$F_t = TLFC_t - TLFC_{(t-1)}$$

Thus, the C placed in a landfill in year *n* is tracked for each year *t* through the end of the inventory period (2009). For example, disposal of food scraps in 1960 resulted in depositing about 1,135,000 metric tons of C. Of this amount, 16 percent (179,000 metric tons) is persistent; the remaining 84 percent (956,000 metric tons) is degradable. By 1965, more than half of the degradable portion (518,000 metric tons) decomposes, leaving a total of 617,000 metric tons (the persistent portion, plus the remainder of the degradable portion).

Continuing the example, by 2009, the total food scraps C originally disposed in 1960 had declined to 179,000 metric tons (i.e., virtually all degradable C had decomposed). By summing the C remaining from 1960 with the C remaining from food scraps disposed in subsequent years (1961 through 2009), the total landfill C from food scraps in 2009 was 35.9 million metric tons. This value is then added to the C stock from grass, leaves, and branches to calculate the total landfill C stock in 2009, yielding a value of 247.1 million metric tons (as shown in Table 7-50). In exactly the same way total net flux is calculated for forest C and harvested wood products, the total net flux of landfill C for yard trimmings and food scraps for a given year (Table 7-48) is the difference in the landfill C stock for that year and the stock in the preceding year. For example, the net change in 2009 shown in Table 7-48 (3.4 Tg C) is equal to the stock in 2009 (247.1 Tg C) minus the stock in 2008 (243.7 Tg C).

The C stocks calculated through this procedure are shown in Table 7-50.

Table 7-49: Moisture Content (%), C Storage Factor, Proportion of Initial C Sequestered (%), Initial C Content (%), and Decay Rate (year^{-1}) for Landfilled Yard Trimmings and Food Scraps in Landfills

	Yard Trimmings			**Food Scraps**
Variable	**Grass**	**Leaves**	**Branches**	
Moisture Content (% H_2O)	70	30	10	70
CS, proportion of initial C stored (%)	53	85	77	16
Initial C Content (%)	45	46	49	51
Decay Rate (year^{-1})	0.323	0.185	0.016	0.156

Table 7-50: C Stocks in Yard Trimmings and Food Scraps in Landfills (Tg C)

Carbon Pool	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
Yard Trimmings	**155.8**	**191.9**	**202.9**	**205.0**	**206.9**	**208.9**	**211.2**
Branches	74.6	92.4	97.5	98.5	99.3	100.2	101.3
Leaves	66.7	82.4	87.3	88.3	89.1	90.1	91.1
Grass	14.5	17.2	18.1	18.2	18.4	18.6	18.8
Food Scraps	**21.3**	**27.0**	**31.7**	**32.7**	**33.7**	**34.8**	**35.9**
Total Carbon Stocks	**177.2**	**218.9**	**234.6**	**237.6**	**240.6**	**243.7**	**247.1**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

The uncertainty analysis for landfilled yard trimmings and food scraps includes an evaluation of the effects of uncertainty for the following data and factors: disposal in landfills per year (tons of C), initial C content, moisture content, decay rate, and proportion of C stored. The C storage landfill estimates are also a function of the composition of the yard trimmings (i.e., the proportions of grass, leaves and branches in the yard trimmings mixture). There are respective uncertainties associated with each of these factors.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-51. Total yard trimmings and food scraps CO_2 flux in 2009 was estimated to be between -21.2 and -6.2 Tg CO_2 Eq. at a 95 percent confidence level (or 19 of 20 Monte Carlo stochastic simulations). This indicates a range of 68 percent below to 51 percent above the 2009 flux estimate of -12.6 Tg CO_2 Eq. More information on the uncertainty estimates for Yard Trimmings and Food Scraps in Landfills is contained within the Uncertainty Annex.

Table 7-51: Tier 2 Quantitative Uncertainty Estimates for CO_2 Flux from Yard Trimmings and Food Scraps in Landfills (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Flux Estimate (Tg CO_2 Eq.)**	**Uncertainty Range Relative to Flux Estimate[a] (Tg CO_2 Eq.)**		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Yard Trimmings and Food Scraps	CO_2	(12.6)	(21.2)	(6.2)	-68%	+51%

[a] Range of flux estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Note: Parentheses indicate negative values or net C sequestration.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation and did not reveal any systematic inaccuracies or incorrect input values.

Recalculations Discussion

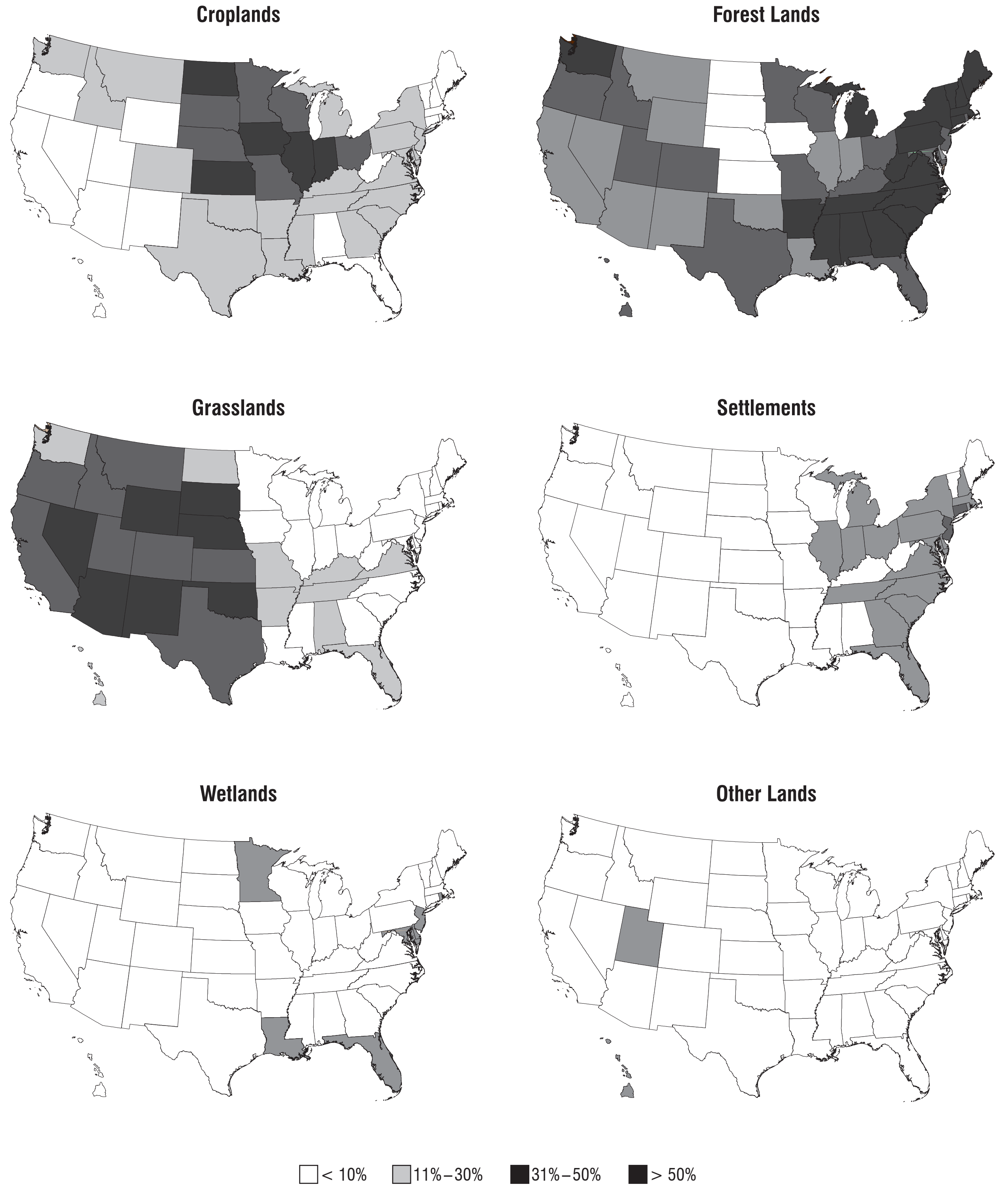
First-order decay rate constants were updated based on De la Cruz and Barlaz (2010), as described in the methodology section. Input data were updated for the years: 1990, 2000, 2005, and 2007 through 2009 based on the updated values reported in *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011). As a result, C storage estimates for those years were revised relative to the previous Inventory. While data inputs for intervening years in the timeseries were not revised, overall C storage in any given year is dependent on the previous year's storage (as shown in the second equation above), and so C storage estimates for those years were also revised. These revisions resulted in an annual average increase in C stored in landfills of 4.2 percent across the timeseries.

Planned Improvements

Future work is planned to evaluate the potential contribution of inorganic C, primarily in the form of carbonates, to landfill sequestration, as well as the consistency between the estimates of C storage described in this chapter and the estimates of landfill CH_4 emissions described in the Waste chapter.

Figure 7-1

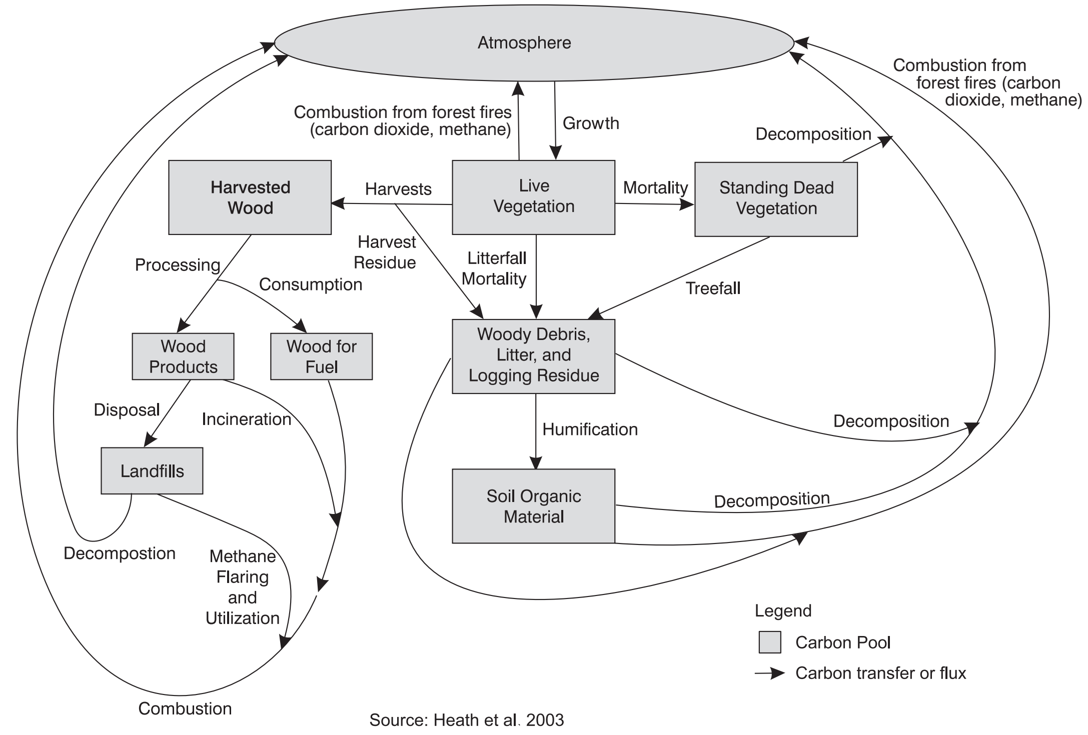
Percent of Total Land Area in the General Land Use Categories for 2009



Note: Land use/land-use change categories were aggregated into the 6 general land-use categories based on the current use in 2009.

Figure 7-2

Forest Sector Carbon Pools and Flows



Source: Heath et al. 2003

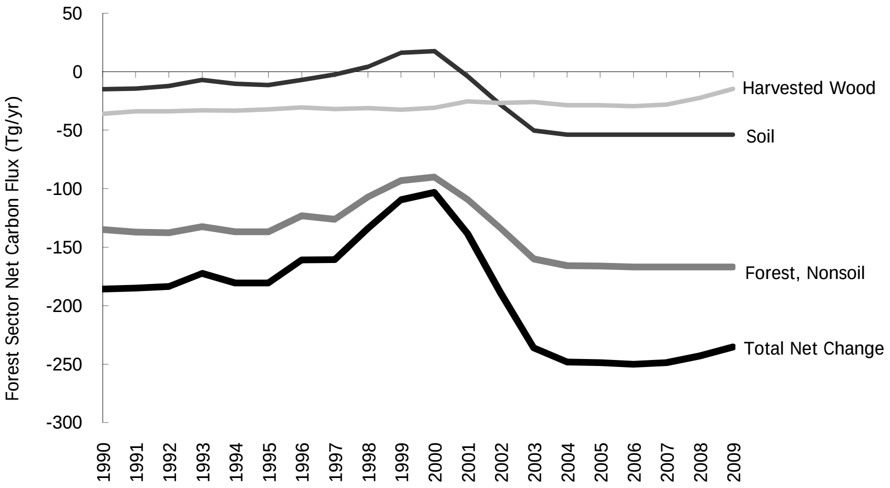


Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4

Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

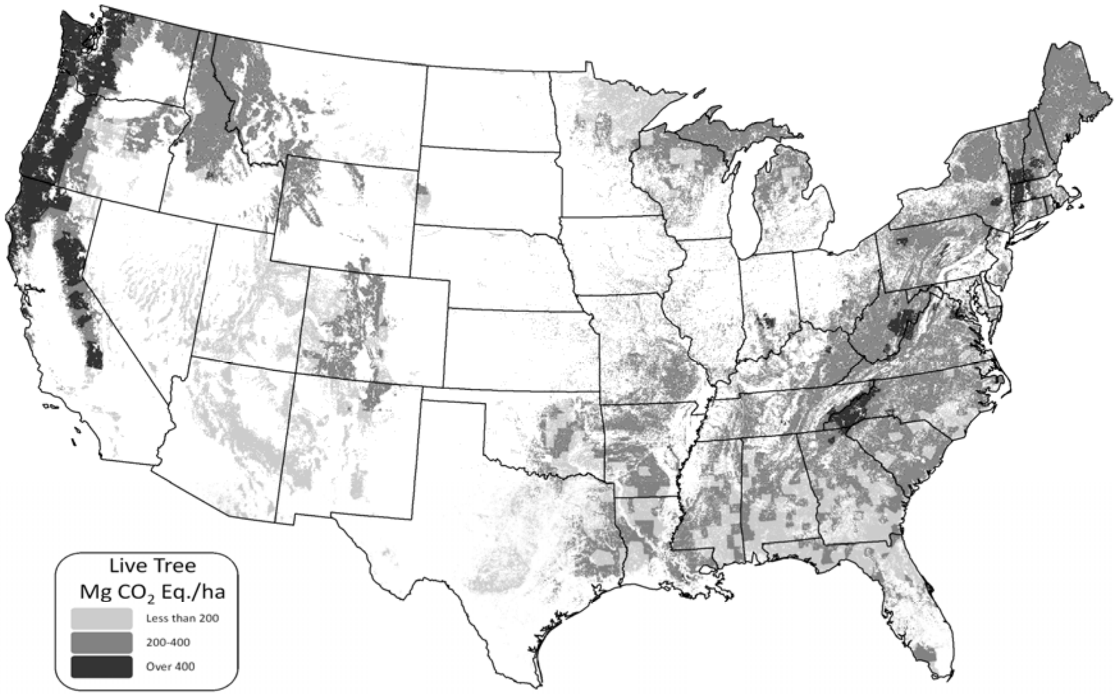
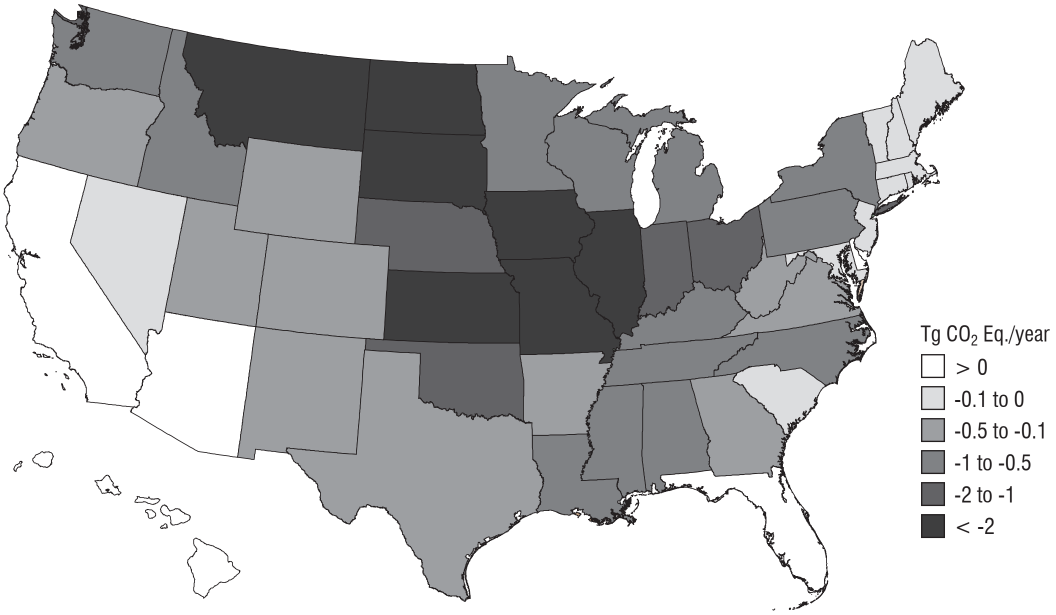


Figure 7-5

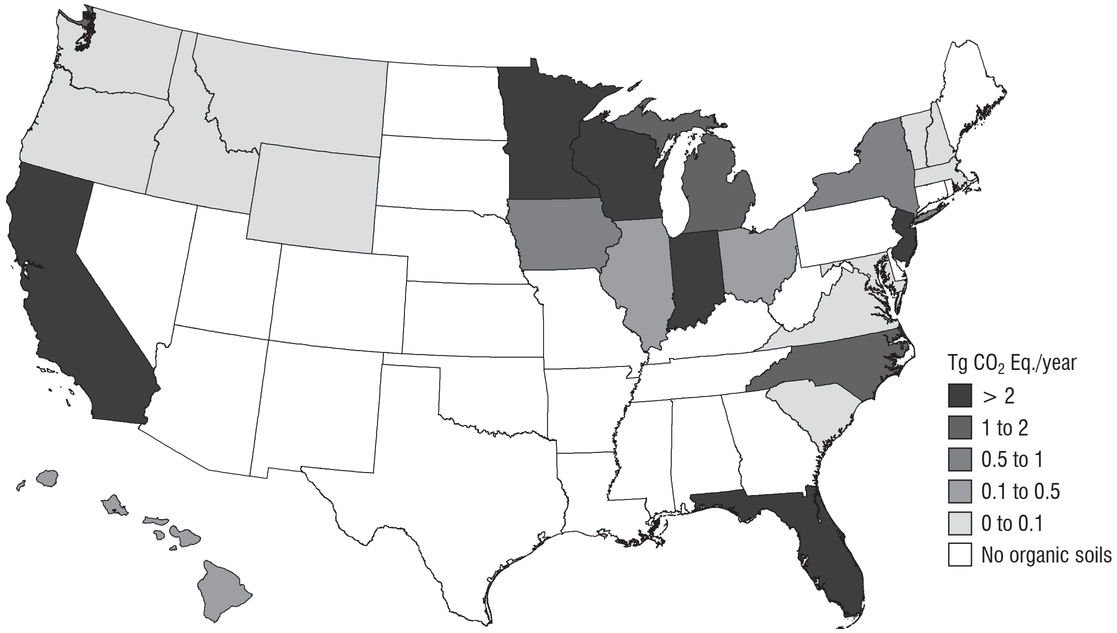
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Cropland Remaining Cropland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-6

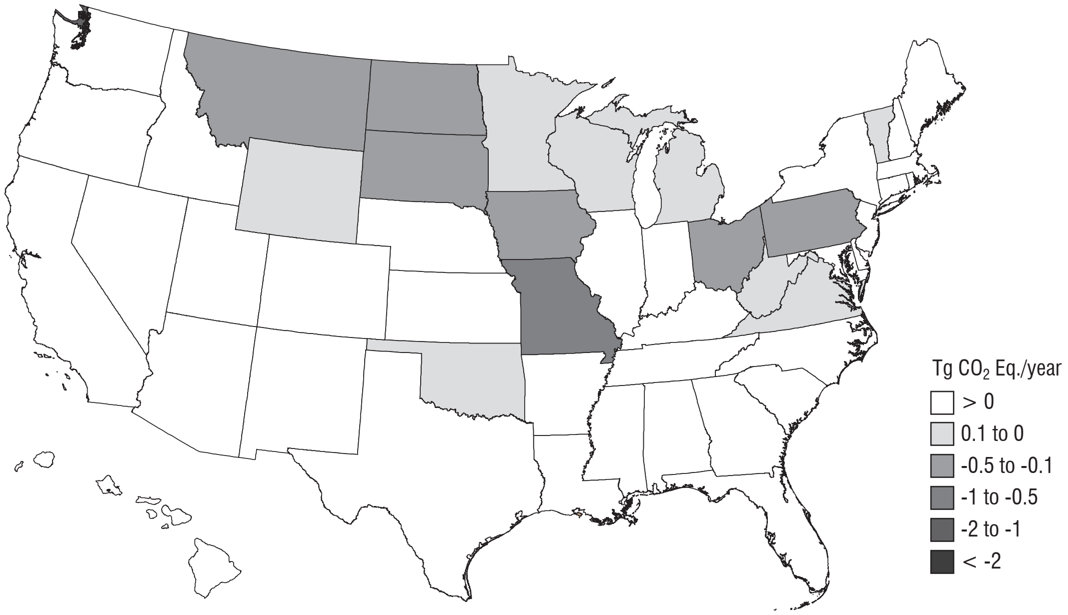
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Cropland Remaining Cropland*



Note: Values greater than zero represent emissions.

Figure 7-7

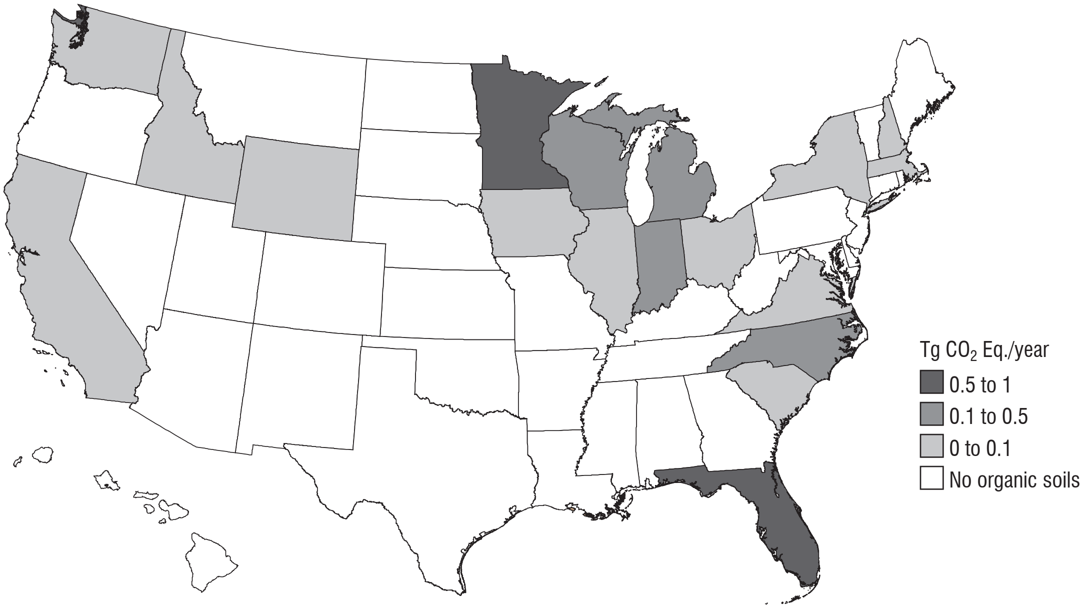
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Land Converted to Cropland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-8

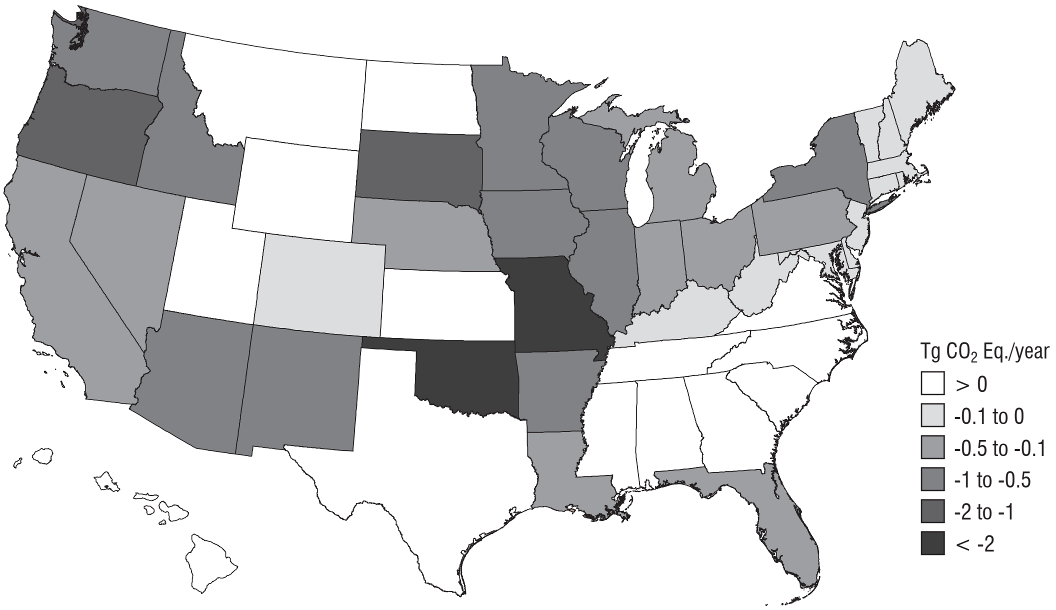
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Land Converted to Cropland*



Note: Values greater than zero represent emissions.

Figure 7-9

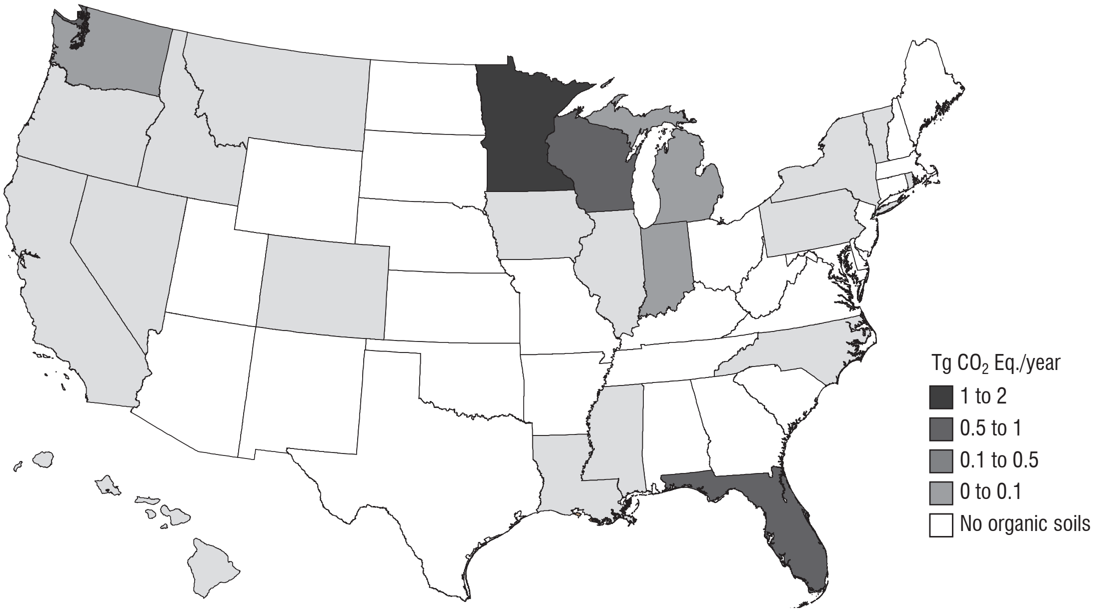
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States, 2009, *Grassland Remaining Grassland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-10

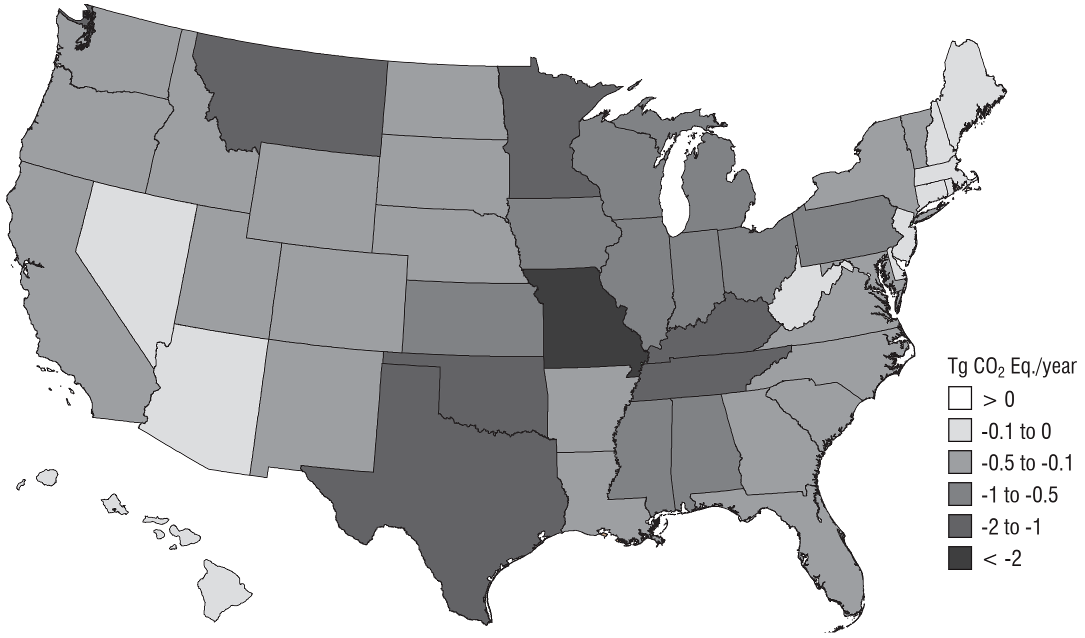
Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Grassland Remaining Grassland*



Note: Values greater than zero represent emissions.

Figure 7-11

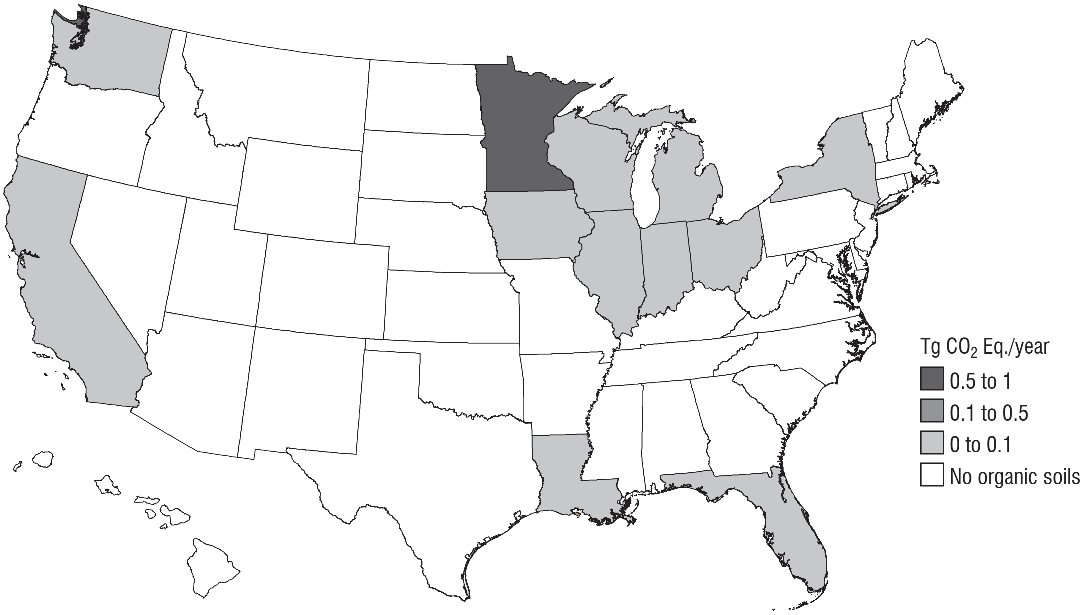
Total Net Annual CO_2 Flux for Mineral Soils Under Agricultural Management within States,
2009, *Land Converted to Grassland*



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-12

Total Net Annual CO_2 Flux for Organic Soils Under Agricultural Management within States, 2009, *Land Converted to Grassland*



Note: Values greater than zero represent emissions.

8. Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 8-1). Landfills accounted for approximately 17 percent of total U.S. anthropogenic methane (CH_4) emissions in 2009, the third largest contribution of any CH_4 source in the United States. Additionally, wastewater treatment and composting of organic waste accounted for approximately 4 percent and less than 1 percent of U.S. CH_4 emissions, respectively. Nitrous oxide (N_2O) emissions from the discharge of wastewater treatment effluents into aquatic environments were estimated, as were N_2O emissions from the treatment process itself. N_2O emissions from composting were also estimated. Together, these waste activities account for less than 3 percent of total U.S. N_2O emissions. Nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) are emitted by waste activities, and are addressed separately at the end of this chapter. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 8-1 and Table 8-2.

CO_2, N_2O, and CH_4 emissions from the incineration of waste are accounted for in the Energy sector rather than in the Waste sector because almost all incineration of municipal solid waste (MSW) in the United States occurs at waste-to-energy facilities where useful energy is recovered. Similarly, the Energy sector also includes an estimate of emissions from burning waste tires because virtually all of the combustion occurs in industrial and utility boilers that recover energy. The incineration of waste in the United States in 2009 resulted in 12.7 Tg CO_2 Eq. emissions, nearly half of which is attributable to the combustion of plastics. For more details on emissions from the incineration of waste, see Section 3.3.

Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

[BEGIN BOX]

Box 8-1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report, and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC).[197] Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[198] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations,[199] but rather this Inventory presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

[END BOX]

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO_2 Eq., or just over 2 percent of total U.S. greenhouse gas emissions.

Table 8-1. Emissions from Waste (Tg CO_2 Eq.)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**171.2**	**138.1**	**138.4**	**137.8**	**137.4**	**142.1**	**143.6**
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5

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[197] See http://www.ipcc-nggip.iges.or.jp/public/index.html.

[198] See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

[199] For example, see http://www.epa.gov/aboutepa/oswer.html.

Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	**4.0**	**5.9**	**6.5**	**6.6**	**6.7**	**6.8**	**6.9**
Domestic Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**175.2**	**143.9**	**144.9**	**144.4**	**144.1**	**149.0**	**150.5**

Note: Totals may not sum due to independent rounding.

Table 8-2. Emissions from Waste (Gg)

Gas/Source	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	**8,152**	**6,576**	**6,591**	**6,563**	**6,541**	**6,769**	**6,840**
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Composting	15	60	75	75	79	80	79
N_2O	**13**	**19**	**21**	**21**	**22**	**22**	**22**
Domestic Wastewater Treatment	12	14	15	16	16	16	16
Composting	1	4	6	6	6	6	6

Note: Totals may not sum due to independent rounding.

8.1. Landfills (IPCC Source Category 6A1)

In 2009, landfill CH_4 emissions were approximately 117.5 Tg CO_2 Eq. (5,593 Gg of CH_4), representing the third largest source of CH_4 emissions in the United States, behind natural gas systems and enteric fermentation. Emissions from municipal solid waste (MSW) landfills, which received about 64.5 percent of the total solid waste generated in the United States, accounted for about 94 percent of total landfill emissions, while industrial landfills accounted for the remainder. Approximately 1,800 operational landfills exist in the United States, with the largest landfills receiving most of the waste and generating the majority of the CH_4 (*BioCycle* 2006, adjusted to include missing data from five states).

After being placed in a landfill, waste (such as paper, food scraps, and yard trimmings) is initially decomposed by aerobic bacteria. After the oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and short-chain organic compounds that form the substrates for the growth of methanogenic bacteria. These CH_4-producing anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas consisting of approximately 50 percent carbon dioxide (CO_2) and 50 percent CH_4, by volume. Significant CH_4 production typically begins one or two years after waste disposal in a landfill and continues for 10 to 60 years or longer.

Methane emissions from landfills are a function of several factors, including: (1) the total amount of waste in MSW landfills, which is related to total waste landfilled annually; (2) the characteristics of landfills receiving waste (i.e., composition of waste-in-place, size, climate); (3) the amount of CH_4 that is recovered and either flared or used for energy purposes; and (4) the amount of CH_4 oxidized in landfills instead of being released into the atmosphere. From 1990 to 2009, net CH_4 emissions from landfills decreased by approximately 20 percent (see Table 8-3 and Table 8-4). This net CH_4 emissions decrease can be attributed to many factors, including changes in waste composition, an increase in the amount of landfill gas collected and combusted, a higher frequency of composting, and increased rates of recovery for degradeable materials (e.g, paper and paperboard).

The estimated annual quantity of waste placed in MSW landfills increased from about 209 Tg in 1990 to 297 Tg in 2009, an increase of 42 percent (see Annex 3.14). Despite increased waste disposal, the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills have decreased by approximately 21 percent from 1990 to 2008 (EPA, 2009b). In addition, the amount of landfill gas collected and combusted has increased. In 1990, for example, approximately 970 Gg of CH_4 were recovered and combusted (i.e., used for energy or flared) from landfills, while in 2009, 7,208 Gg CH_4 was combusted, which represents a 3 percent increase in the quantity of CH_4 recovered and combusted from 2008 levels. In 2009, an estimated 49 new landfill gas-to-energy (LFGTE) projects and 32 new flares began operation.

Over the past 9 years, however, the net CH_4 emissions have fluctuated from year to year, but a slowly increasing trend has been observed. While the amount of landfill gas collected and combusted continues to increase every year, the rate of increase in collection and combustion no longer exceeds the rate of additional CH_4 generation from the amount of organic MSW landfilled as the U.S. population grows.

Over the next several years, the total amount of municipal solid waste generated is expected to increase as the U.S. population continues to grow. The percentage of waste landfilled, however, may decline due to increased recycling and composting practices. In addition, the quantity of CH_4 that is recovered and either flared or used for energy purposes is expected to continue to increase as a result of 1996 federal regulations that require large municipal solid waste landfills to collect and combust landfill gas (see 40 CFR Part 60, Subpart Cc 2005 and 40 CFR Part 60, Subpart WWW 2005), voluntary programs that encourage CH_4 recovery and use such as EPA's Landfill Methane Outreach Program (LMOP), and federal and state incentives that promote renewable energy (e.g., tax credits, low interest loans, and Renewable Portfolio Standards).

Table 8-3. CH_4 Emissions from Landfills (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
MSW Landfills	172.6	206.9	241.2	248.1	254.2	260.3	266.3
Industrial Landfills	11.5	14.3	15.2	15.3	15.4	15.5	15.6
Recovered							
Gas-to-Energy	(13.6)	(49.4)	(56.5)	(59.0)	(63.7)	(67.0)	(72.0)
Flared	(6.7)	(47.8)	(74.9)	(80.2)	(82.3)	(80.0)	(79.4)
Oxidized[a]	(16.4)	(12.4)	(12.5)	(12.4)	(12.4)	(12.9)	(13.1)
Total	**147.4**	**111.7**	**112.5**	**111.7**	**111.3**	**115.9**	**117.5**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

[a] Includes oxidation at both municipal and industrial landfills.

Table 8-4. CH_4 Emissions from Landfills (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
MSW Landfills	8,219	9,854	11,486	11,813	12,107	12,395	12,679
Industrial Landfills	549	682	724	727	732	738	744
Recovered							
Gas-to-Energy	(649)	(2,352)	(2,691)	(2,807)	(3,033)	(3,189)	(3,429)
Flared	(321)	(2,276)	(3,566)	(3,820)	(3,918)	(3,810)	(3,779)
Oxidized[a]	(780)	(591)	(596)	(592)	(589)	(614)	(622)
Total	**7,018**	**5,317**	**5,358**	**5,321**	**5,299**	**5,520**	**5,593**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

[a] Includes oxidation at municipal and industrial landfills.

Methodology

A detailed description of the methodology used to estimate CH_4 emissions from landfills can be found in Annex 3.14.

CH_4 emissions from landfills were estimated as the CH_4 produced from municipal solid waste landfills, plus the CH_4 produced by industrial landfills, minus the CH_4 recovered and combusted, minus the CH_4 oxidized before being released into the atmosphere:

$$CH_{4,\text{Solid Waste}} = [CH_{4,MSW} + CH_{4,Ind} - R] - Ox$$

where,

$CH_{4,\text{Solid Waste}}$ = CH_4 emissions from solid waste
$CH_{4,MSW}$ = CH_4 generation from municipal solid waste landfills,
$CH_{4,Ind}$ = CH_4 generation from industrial landfills,
R = CH_4 recovered and combusted, and
Ox = CH_4 oxidized from MSW and industrial landfills before release to the atmosphere.

The methodology for estimating CH_4 emissions from municipal solid waste landfills is based on the first order decay model described by the Intergovernmental Panel on Climate Change (IPCC 2006). Values for the CH_4 generation potential (L_0) and rate constant (k) were obtained from an analysis of CH_4 recovery rates for a database of 52 landfills and from published studies of other landfills (RTI 2004; EPA 1998; SWANA 1998; Peer, Thorneloe, and Epperson 1993). The rate constant was found to increase with average annual rainfall; consequently, values of k were developed for 3 ranges of rainfall. The annual quantity of waste placed in landfills was apportioned to the 3 ranges of rainfall based on the percent of the U.S. population in each of the 3 ranges, and historical census data were used to account for the shift in population to more arid areas over time. For further information, see Annex 3.14.

National landfill waste generation and disposal data for 2007, 2008, and 2009 were extrapolated based on *BioCycle* data and the U.S. Census population from 2009. Data for 1989 through 2006 were obtained from *BioCycle* (2008). Because *BioCycle* does not account for waste generated in U.S. territories, waste generation for the territories was estimated using population data obtained from the U.S. Census Bureau (2010) and national per capita solid waste generation from *BioCycle* (2008). Estimates of the annual quantity of waste landfilled for 1960 through 1988 were obtained from EPA's *Anthropogenic Methane Emissions in the United States, Estimates for 1990: Report to Congress* (EPA 1993) and an extensive landfill survey by the EPA's Office of Solid Waste in 1986 (EPA 1988). Although waste placed in landfills in the 1940s and 1950s contributes very little to current CH_4 generation, estimates for those years were included in the first order decay model for completeness in accounting for CH_4 generation rates and are based on the population in those years and the per capita rate for land disposal for the 1960s. For calculations in this inventory, wastes landfilled prior to 1980 were broken into two groups: wastes disposed in landfills (Methane Conversion Factor, MCF, of 1) and those disposed in dumps (MCF of 0.6). Please see Annex 3.14 for more details.

The estimated landfill gas recovered per year was based on updated data collected from vendors of flaring equipment, a database of landfill gas-to-energy (LFGTE) projects compiled by LMOP (EPA 2009a), and a database maintained by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007). As the EIA database only included data through 2006; 2007 to 2009 recovery for projects included in the EIA database were assumed to be the same as in 2006. The three databases were carefully compared to identify landfills that were in two or all three of the databases to avoid double counting reductions. Based on the information provided by the EIA and flare vendor databases, the CH_4 combusted by flares in operation from 1990 to 2009 was estimated. This quantity likely underestimates flaring because these databases do not have information on all flares in operation. Additionally, the EIA and LMOP databases provided data on landfill gas flow and energy generation for landfills with LFGTE projects. If a landfill in the EIA database was also in the LMOP and/or the flare vendor database, the emissions avoided were based on the EIA data because landfill owners or operators reported the amount recovered based on measurements of gas flow and concentration, and the reporting accounted for changes over time. If both flare data and LMOP recovery data were available for any of the remaining landfills (i.e., not in the EIA database), then the emissions recovery was based on the LMOP data, which provides reported landfill-specific data on gas flow for direct use projects and project capacity (i.e., megawatts) for electricity projects. The flare data, on the other hand, only provided a range of landfill gas flow for a given flare size. Given that each LFGTE project is likely to also have a flare, double counting reductions from flares and LFGTE projects in the LMOP database was avoided by subtracting emission reductions associated with LFGTE projects for which a flare had not been identified from the emission reductions associated with flares. A further explanation of the improvements made to estimate the landfill gas recovered for the current Inventory can be found in Annex 3.14.

A destruction efficiency of 99 percent was applied to CH_4 recovered to estimate CH_4 emissions avoided. The value for efficiency was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in EPA's AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used in LMOP.

Emissions from industrial landfills were estimated from activity data for industrial production (ERG 2010), waste disposal factors, and the first order decay model. As over 99 percent of the organic waste placed in industrial landfills originated from the food processing (meat, vegetables, fruits) and pulp and paper industries, estimates of industrial landfill emissions focused on these two sectors (EPA 1993). The amount of CH_4 oxidized by the landfill cover at both municipal and industrial landfills was assumed to be ten percent of the CH_4 generated that is not recovered (IPCC 2006, Mancinelli and McKay 1985, Czepiel et al. 1996). To calculate net CH_4 emissions, both CH_4 recovered and CH_4 oxidized were subtracted from CH_4 generated at municipal and industrial landfills.

Uncertainty and Time-Series Consistency

Several types of uncertainty are associated with the estimates of CH_4 emissions from landfills. The primary uncertainty concerns the characterization of landfills. Information is not available on two fundamental factors affecting CH_4 production: the amount and composition of waste placed in every landfill for each year of its operation. The approach used here assumes that the CH_4 generation potential and the rate of decay that produces CH_4, as determined from several studies of CH_4 recovery at landfills, are representative of U.S. landfills.

Additionally, the approach used to estimate the contribution of industrial wastes to total CH_4 generation introduces uncertainty. Aside from uncertainty in estimating CH_4 generation potential, uncertainty exists in the estimates of oxidation by cover soils. There is also uncertainty in the estimates of CH_4 that is recovered by flaring and energy projects. The IPCC default value of 10 percent for uncertainty in recovery estimates was used in the uncertainty analysis when metering was in place (for about 64 percent of the CH_4 estimated to be recovered). For flaring without metered recovery data (approximately 34 percent of the CH_4 estimated to be recovered), a much higher uncertainty of approximately 50 percent was used (e.g., when recovery was estimated as 50 percent of the flare's design capacity).

N_2O emissions from the application of sewage sludge on landfills are not explicitly modeled as part of greenhouse gas emissions from landfills. N_2O emissions from sewage sludge applied to landfills would be relatively small because the microbial environment in landfills is not very conducive to the nitrification and denitrification processes that result in N_2O emissions. Furthermore, the 2006 IPCC Guidelines (IPCC 2006) did not include a methodology for estimating N_2O emissions from solid waste disposal sites "because they are not significant." Therefore, any uncertainty or bias caused by not including N_2O emissions from landfills is expected to be minimal.

The results of the IPCC Good Practice Guidance Tier 2 quantitative uncertainty analysis are summarized in Table 8-5. Landfill CH_4 emissions in 2009 were estimated to be between 61.1 and 164.5 Tg CO_2 Eq., which indicates a range of 48 percent below to 40 percent above the 2009 emission estimate of 117.5 Tg CO_2 Eq.

Table 8-5. Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Landfills (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Landfills	**CH_4**	**117.5**	**61.1**	**164.5**	**-48%**	**+40%**
MSW	CH_4	103.4	61.0	167.5	-41%	+62%
Industrial	CH_4	14.1	10.2	17.1	-28%	+21%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. A primary focus of the QA/QC checks was to ensure that CH_4 recovery estimates were not double-counted. Both manual and electronic checks were made to ensure that emission avoidance from each landfill was calculated in only one of the three databases. The primary calculation spreadsheet is tailored from the IPCC waste model and has been verified previously using the original, peer-reviewed IPCC waste model. All model input values were verified by secondary QA/QC review.

Recalculations Discussion

In developing the current Inventory, a separate Monte Carlo analysis was conducted for MSW and industrial landfills to better characterize the greater amount of uncertainty surrounding industrial waste data. Additional steps were also taken to better characterize the food waste decay rate and the methodology for the flare correction factor. A weighted component-specific decay rate for food waste of 0.156 yr^{-1} was used in the current Inventory as recommended by ICF International (2009). This replaced the previous Inventory's default food waste decay rate of 0.185 yr^{-1} and resulted in a decrease of landfill emissions of less than 1 percent. The majority of changes in CH_4 emissions from landfills over the time series resulted from improvements made to the flare correction factor to better associate flares in the flare vendor database with a landfill and/or Landfill Gas to Energy (LFGTE) project in the

EIA and LMOP databases.

The flare correction factor for the 1990 through 2008 Inventory report consisted of approximately 512 cases where flares were not directly associated with a landfill and/or LFGTE project in the EIA and/or LMOP databases. For these projects, CH_4 avoided would be overestimated as both the CH_4 avoided from flaring and the LFGTE project would be counted. To abstain from overestimating emissions avoided from flaring, the CH_4 avoided from flares with no identified landfill or LFGTE project were determined and the flaring estimate from the flare vendor database was reduced by this quantity (referred to as a flare correction factor) on a state-by-state basis.

If comprehensive data on flares were available, the majority of LFGTE projects in the EIA and LMOP databases would have an identified flare because it is assumed that most LFGTE projects have flares. However, given that the flare vendor data only covers approximately 50 to 75 percent of the flare population, an associated flare was not identified for all LFGTE projects. These LFGTE projects likely have flares; however, flares were unable to be identified due to one of two reasons: (1) inadequate identifier information provided by the flare vendor; or (2) a lack of the flare in the flare vendor database.

Additional effort was undertaken to improve the methodology behind the flare correction factor for the current Inventory to reduce the overall number of flares that were not matched (512) to landfills and/or LFGTE projects in the EIA and LMOP databases. Each flare in the flare vendor database not associated with a LFGTE project in the EIA or LMOP databases was investigated to determine if it could be matched to either a landfill in the EIA database or a LFGTE project in the LMOP database. For some unmatched flares, the location information was missing or incorrectly transferred to the flare vendor database. In other instances, the landfill names were slightly different between what the flare vendor provided and the actual landfill name as listed in the EIA and/or LMOP databases.

It was found that a large majority of the unidentified flares are associated with landfills in LMOP that are currently flaring, but are also considering LFGTE. These landfill projects considering a LFGTE project are labeled as candidate, potential, or construction in the LMOP database. The flare vendor database was improved to match flares with operational, shutdown as well as candidate, potential, and construction LFGTE projects, thereby reducing the total number of unidentified flares in the flare vendor database, all of which are used in the flare correction factor. The results of this effort significantly decreased the number of flares used in the flare correction factor from 512 to 27, impacted emission estimates for the entire time series, and resulted in an average annual decrease of 8.2 Tg CO_2 Eq. (6.5 percent) in CH_4 emissions from the Landfills source category for the period 1990 through 2008.

Planned Improvements

Beginning in 2010, all MSW landfills that accepted waste on or after January 1, 1980 and generate CH_4 in amounts equivalent to 25,000 metric tons or more of carbon dioxide equivalent (CO_2 Eq.) will be required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program (GHGRP). This consists of the landfill, landfill gas collection systems, and landfill gas destruction devices, including flares. In addition to reporting greenhouse gas information to EPA, landfill-specific characteristics such as annual waste disposal quantity, waste composition data, surface area, and cover type must also be reported. The data collected from the GHGRP will be used in future inventories to revise the parameters used in the CH_4 generation calculations, including degradeable organic carbon (DOC), the flare correction factor, the methane correction factor (MCF), fraction of DOC dissimilated (DOC_F), the destruction efficiency of flares, the oxidation factor (Ox), and the rate constant (k). The addition of this higher tier data will improve the emission calculations to provide a more accurate representation of gresnhouse gas emissions from MSW landfills.

[Begin Text Box]

Box 8-1: Biogenic Wastes in Landfills

Regarding the depositing of wastes of biogenic origin in landfills, empirical evidence shows that some of these wastes degrade very slowly in landfills, and the C they contain is effectively sequestered in landfills over a period of time (Barlaz 1998, 2006). Estimates of C removals from landfilling of forest products, yard trimmings, and food scraps are further described in the Land Use, Land-Use Change, and Forestry chapter, based on methods presented in IPCC (2003) and IPCC (2006).

[End Box]

8.2. *Wastewater Treatment (IPCC Source Category 6B)*

Wastewater treatment processes can produce anthropogenic CH_4 and N_2O emissions. Wastewater from domestic[200] and industrial sources is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants. Treatment may either occur on site, most commonly through septic systems or package plants, or off site at centralized treatment systems. Centralized wastewater treatment systems may include a variety of processes, ranging from lagooning to advanced tertiary treatment technology for removing nutrients. In the United States, approximately 20 percent of domestic wastewater is treated in septic systems or other on-site systems, while the rest is collected and treated centrally (U.S. Census Bureau 2009).

Soluble organic matter is generally removed using biological processes in which microorganisms consume the organic matter for maintenance and growth. The resulting biomass (sludge) is removed from the effluent prior to discharge to the receiving stream. Microorganisms can biodegrade soluble organic material in wastewater under aerobic or anaerobic conditions, where the latter condition produces CH_4. During collection and treatment, wastewater may be accidentally or deliberately managed under anaerobic conditions. In addition, the sludge may be further biodegraded under aerobic or anaerobic conditions. The generation of N_2O may also result from the treatment of domestic wastewater during both nitrification and denitrification of the N present, usually in the form of urea, ammonia, and proteins. These compounds are converted to nitrate (NO_3) through the aerobic process of nitrification. Denitrification occurs under anoxic conditions (without free oxygen), and involves the biological conversion of nitrate into dinitrogen gas (N_2). N_2O can be an intermediate product of both processes, but is more often associated with denitrification.

The principal factor in determining the CH_4 generation potential of wastewater is the amount of degradable organic material in the wastewater. Common parameters used to measure the organic component of the wastewater are the Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD). Under the same conditions, wastewater with higher COD (or BOD) concentrations will generally yield more CH_4 than wastewater with lower COD (or BOD) concentrations. BOD represents the amount of oxygen that would be required to completely consume the organic matter contained in the wastewater through aerobic decomposition processes, while COD measures the total material available for chemical oxidation (both biodegradable and non-biodegradable). Because BOD is an aerobic parameter, it is preferable to use COD to estimate CH_4 production. The principal factor in determining the N_2O generation potential of wastewater is the amount of N in the wastewater.

In 2009, CH_4 emissions from domestic wastewater treatment were 16.0 Tg CO_2 Eq. (760 Gg). Emissions gradually increased from 1990 through 1997, but have decreased since that time due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems. In 2009, CH_4 emissions from industrial wastewater treatment were estimated to be 8.5 Tg CO_2 Eq. (407 Gg). Industrial emission sources have increased across the time series through 1999 and then fluctuated up and down with production changes associated with the treatment of wastewater from the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries. Table 8-6 and Table 8-7 provide CH_4 and N_2O emission estimates from domestic and industrial wastewater treatment.

With respect to N_2O, the United States identifies two distinct sources for N_2O emissions from domestic wastewater: emissions from centralized wastewater treatment processes, and emissions from effluent from centralized treatment systems that has been discharged into aquatic environments. The 2009 emissions of N_2O from centralized wastewater treatment processes and from effluent were estimated to be 0.3 Tg CO_2 Eq. (1 Gg) and 4.7 Tg CO_2 Eq. (15.2 Gg), respectively. Total N_2O emissions from domestic wastewater were estimated to be 5.0 Tg CO_2 Eq. (16.2 Gg). N_2O emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

Table 8-6. CH_4 and N_2O Emissions from Domestic and Industrial Wastewater Treatment (Tg CO_2 Eq.)

Activity	**1990**		**2000**		**2005**	**2006**	**2007**	**2008**	**2009**

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[200] Throughout the inventory, emissions from domestic wastewater also include any commercial and industrial wastewater collected and co-treated with domestic wastewater.

CH_4	**23.5**		**25.2**		**24.3**	**24.5**	**24.4**	**24.5**	**24.5**
Domestic	16.4		16.8		16.2	16.0	15.9	15.8	16.0
Industrial*	7.1		8.4		8.2	8.5	8.5	8.6	8.5
N_2O	**3.7**		**4.5**		**4.8**	**4.8**	**4.9**	**5.0**	**5.0**
Domestic	3.7		4.5		4.8	4.8	4.9	5.0	5.0
Total	**27.2**		**29.6**		**29.1**	**29.3**	**29.3**	**29.5**	**29.5**

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Table 8-7. CH_4 and N_2O Emissions from Domestic and Industrial Wastewater Treatment (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
CH_4	**1,118**		**1,199**		**1,159**	**1,167**	**1,163**	**1,168**	**1,167**
Domestic	780		801		770	764	758	759	760
Industrial*	338		398		389	403	405	409	407
N_2O	**12**		**14**		**15**	**16**	**16**	**16**	**16**
Domestic	12		14		15	16	16	16	16

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Methodology

Domestic Wastewater CH_4 Emission Estimates

Domestic wastewater CH_4 emissions originate from both septic systems and from centralized treatment systems, such as publicly owned treatment works (POTWs). Within these centralized systems, CH_4 emissions can arise from aerobic systems that are not well managed or that are designed to have periods of anaerobic activity (e.g., constructed wetlands), anaerobic systems (anaerobic lagoons and facultative lagoons), and from anaerobic digesters when the captured biogas is not completely combusted. CH_4 emissions from septic systems were estimated by multiplying the total 5-day BOD (BOD_5) produced in the United States by the percent of wastewater treated in septic systems (20 percent), the maximum CH_4 producing capacity for domestic wastewater (0.60 kg CH_4/kg BOD), and the CH_4 correction factor (MCF) for septic systems (0.5). CH_4 emissions from POTWs were estimated by multiplying the total BOD_5 produced in the United States by the percent of wastewater treated centrally (80 percent), the relative percentage of wastewater treated by aerobic and anaerobic systems, the relative percentage of wastewater facilities with primary treatment, the percentage of BOD_5 treated after primary treatment (67.5 percent), the maximum CH_4-producing capacity of domestic wastewater (0.6), and the relative MCFs for aerobic (zero or 0.3) and anaerobic (0.8) systems with all aerobic systems assumed to be well-managed. CH_4 emissions from anaerobic digesters were estimated by multiplying the amount of biogas generated by wastewater sludge treated in anaerobic digesters by the proportion of CH_4 in digester biogas (0.65), the density of CH_4 (662 g CH_4/m^3 CH_4) , and the destruction efficiency associated with burning the biogas in an energy/thermal device (0.99). The methodological equations are:

Emissions from Septic Systems = A
= (% onsite) × (total BOD_5 produced) × (B_o) × (MCF-septic) × 1/10^6

Emissions from Centrally Treated Aerobic Systems = B
= [(% collected) × (total BOD_5 produced) × (% aerobic) × (% aerobic w/out primary) + (% collected) × (total BOD_5 produced) × (% aerobic) × (% aerobic w/primary) × (1-% BOD removed in prim. treat.)] × (% operations not well managed) × (B_o) × (MCF-aerobic_not_well_man) × 1/10^6

Emissions from Centrally Treated Anaerobic Systems = C
= [(% collected) × (total BOD_5 produced) × (% anaerobic) × (% anaerobic w/out primary) + (% collected) × (total BOD_5 produced) × (% anaerobic) × (% anaerobic w/primary) × (1-%BOD removed in prim. treat.)] × (B_o) × (MCF-anaerobic) × 1/10^6

Emissions from Anaerobic Digesters = D
= [(POTW_flow_AD) × (digester gas)/ (per capita flow)] × conversion to m^3 × (FRAC_CH_4) × (365.25) × (density of CH_4) × (1-DE) × 1/10^9

Total CH_4 Emissions (Gg) = A + B + C + D

Where:

% onsite = Flow to septic systems / total flow
% collected = Flow to POTWs / total flow
% aerobic = Flow to aerobic systems / total flow to POTWs
% anaerobic = Flow to anaerobic systems / total flow to POTWs
% aerobic w/out primary = Percent of aerobic systems that do not employ primary treatment
% aerobic w/primary = Percent of aerobic systems that employ primary treatment
% BOD removed in prim. treat. = 32.5%
% operations not well managed = Percent of aerobic systems that are not well managed and in which some anaerobic degradation occurs
% anaerobic w/out primary = Percent of anaerobic systems that do not employ primary treatment
% anaerobic w/primary = Percent of anaerobic systems that employ primary treatment
Total BOD_5 produced = kg BOD/capita/day × U.S. population × 365.25 days/yr
B_o = Maximum CH_4-producing capacity for domestic wastewater (0.60 kg CH_4/kg BOD)
MCF-septic = CH_4 correction factor for septic systems (0.5)
1/10^6 = Conversion factor, kg to Gg
MCF-aerobic_not_well_man. = CH_4 correction factor for aerobic systems that are not well managed (0.3)
MCF-anaerobic = CH_4 correction factor for anaerobic systems (0.8)
DE = CH_4 destruction efficiency from flaring or burning in engine (0.99 for enclosed flares)
POTW_flow_AD = Wastewater influent flow to POTWs that have anaerobic digesters (gal)
digester gas = Cubic feet of digester gas produced per person per day (1.0 ft^3/person/day) (Metcalf and Eddy 1991)
per capita flow = Wastewater flow to POTW per person per day (100 gal/person/day)
conversion to m^3 = Conversion factor, ft^3 to m^3 (0.0283)
FRAC_CH_4 = Proportion CH_4 in biogas (0.65)
density of CH_4 = 662 (g CH_4/m^3 CH_4)
1/10^9 = Conversion factor, g to Gg

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. Table 8-8 presents U.S. population and total BOD_5 produced for 1990 through 2009, while Table 8-9 presents domestic wastewater CH_4 emissions for both septic and centralized systems in 2009. The proportions of domestic wastewater treated onsite versus at centralized treatment plants were based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Surveys conducted by the U.S. Census Bureau (U.S. Census 2009), with data for intervening years obtained by linear interpolation. The percent of wastewater flow to aerobic and anaerobic systems, the percent of aerobic and anaerobic systems that do and do not employ primary treatment, and the wastewater flow to POTWs that have anaerobic digesters were obtained from the 1992, 1996, 2000, and 2004 Clean Watershed Needs Survey (EPA 1992, 1996, 2000, and 2004a). Data for intervening years were obtained by linear interpolation and the years 2004 through 2009 were forecasted from the rest of the time series. The BOD_5 production rate (0.09 kg/capita/day) and the percent BOD_5 removed by primary treatment for domestic wastewater were obtained from Metcalf and Eddy (1991 and 2003). The CH_4 emission factor (0.6 kg CH_4/kg BOD_5) and the MCFs were taken from IPCC (2006). The CH_4 destruction efficiency for methane recovered from sludge digestion operations, 99 percent, was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used by the Landfill Methane Outreach Program (LMOP). The cubic feet of digester gas produced per person per day (1.0 ft^3/person/day) and the proportion of CH_4 in biogas (0.65) come from

Metcalf and Eddy (1991). The wastewater flow to a POTW (100 gal/person/day) was taken from the Great Lakes-Upper Mississippi River Board of State and Provincial Public Health and Environmental Managers, "Recommended Standards for Wastewater Facilities (Ten-State Standards)" (2004).

Table 8-8. U.S. Population (Millions) and Domestic Wastewater BOD_5 Produced (Gg)

Year	Population	BOD_5
1990	254	8,333
2000	286	9,414
2005	300	9,864
2006	303	9,958
2007	306	10,057
2008	309	10,149
2009	311	10,236

Source: U.S. Census Bureau (2010); Metcalf & Eddy 1991 and 2003.

Table 8-9. Domestic Wastewater CH_4 Emissions from Septic and Centralized Systems (2009)

	CH_4 emissions (Tg CO_2 Eq.)	% of Domestic Wastewater CH_4
Septic Systems	13.2	82.5%
Centralized Systems	2.8	17.5%
Total	**16.0**	**100%**

Note: Totals may not sum due to independent rounding.

Industrial Wastewater CH_4 Emission Estimates

CH_4 emissions estimates from industrial wastewater were developed according to the methodology described in IPCC (2006). Industry categories that are likely to produce significant CH_4 emissions from wastewater treatment were identified. High volumes of wastewater generated and a high organic wastewater load were the main criteria. The top five industries that meet these criteria are pulp and paper manufacturing; meat and poultry processing; vegetables, fruits, and juices processing; starch-based ethanol production; and petroleum refining. Wastewater treatment emissions for these sectors for 2009 are displayed in Table 8-10 below. Table 8-11 contains production data for these industries.

Table 8-10. Industrial Wastewater CH_4 Emissions by Sector (2009)

	CH_4 emissions (Tg CO_2 Eq.)	% of Industrial Wastewater CH_4
Pulp & Paper	4.1	48%
Meat & Poultry	3.6	42%
Petroleum Refineries	0.6	7%
Fruit & Vegetables	0.1	1%
Ethanol Refineries	0.1	1%
Total	**8.5**	**100%**

Note: Totals may not sum due to independent rounding.

Table 8-11. U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (Tg)

Year	Pulp and Paper	Meat (Live Weight Killed)	Poultry (Live Weight Killed)	Vegetables, Fruits and Juices	Ethanol	Petroleum Refining
1990	128.9	27.3	14.6	38.7	2.7	702.4
2000	142.8	32.1	22.2	50.9	4.9	795.2
2005	131.4	31.4	25.1	42.9	11.7	818.6
2006	137.4	32.5	25.5	42.9	14.5	826.7
2007	135.9	33.4	26.0	44.7	19.4	827.6
2008	134.5	34.4	26.6	45.1	26.9	836.8

2009	137.0	33.8	25.2	47.0	31.7	822.4

CH_4 emissions from these categories were estimated by multiplying the annual product output by the average outflow, the organics loading (in COD) in the outflow, the percentage of organic loading assumed to degrade anaerobically, and the emission factor. Ratios of BOD:COD in various industrial wastewaters were obtained from EPA (1997a) and used to estimate COD loadings. The B_o value used for all industries is the IPCC default value of 0.25 kg CH_4/kg COD (IPCC 2006).

For each industry, the percent of plants in the industry that treat wastewater on site, the percent of plants that have a primary treatment step prior to biological treatment, and the percent of plants that treat wastewater anaerobically were defined. The percent of wastewater treated anaerobically onsite (TA) was estimated for both primary treatment and secondary treatment. For plants that have primary treatment in place, an estimate of COD that is removed prior to wastewater treatment in the anaerobic treatment units was incorporated.

The methodological equations are:

$$CH_4 \text{ (industrial wastewater)} = P \times W \times COD \times \%TA \times B_o \times MCF$$

$$\%TA_p = [\%Plants_o \times \%WW_{a,p} \times \%COD_p]$$

$$\%TA_s = [\%Plants_a \times \%WW_{a,s} \times \%COD_s] + [\%Plants_t \times \%WW_{a,t} \times \%COD_s]$$

Where:

CH_4 (industrial wastewater) = Total CH_4 emissions from industrial wastewater (kg/year)
P = Industry output (metric tons/year)
W = Wastewater generated (m^3/metric ton of product)
COD = Organics loading in wastewater (kg/m^3)
%TA = Percent of wastewater treated anaerobically on site
$\%TA_p$ = Percent of wastewater treated anaerobically on site in primary treatment
$\%TA_s$ = Percent of wastewater treated anaerobically on site in secondary treatment
$\%Plants_o$ = Percent of plants with onsite treatment
$\%WW_{a,p}$ = Percent of wastewater treated anaerobically in primary treatment
$\%COD_p$ = Percent of COD entering primary treatment
$\%Plants_a$ = Percent of plants with anaerobic secondary treatment
$\%Plants_t$ = Percent of plants with other secondary treatment
$\%WW_{a,s}$ = Percent of wastewater treated anaerobically in anaerobic secondary treatment
$\%WW_{a,t}$ = percent of wastewater treated anaerobically in other secondary treatment
$\%COD_s$ = percent of COD entering secondary treatment
B_o = Maximum CH_4 producing potential of industrial wastewater (default value of 0.25 kg CH_4/kg COD)
MCF = CH_4 correction factor, indicating the extent to which the organic content (measured as COD) degrades anaerobically

As described below, the values presented in Table 8-12 were used in the emission calculations.

Table 8-12. Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (%)

Variable	**Industry**						
	Pulp and Paper	**Meat Processing**	**Poultry Processing**	**Fruit/ Vegetable Processing**	**Ethanol Production – Wet Mill**	**Ethanol Production – Dry Mill**	**Petroleum Refining**
$\%TA_p$	0	0	0	0	0	0	0
$\%TA_s$	10.5	33	25	4.2	33.3	75	100
$\%Plants_o$	60	100	100	11	100	100	100
$\%Plants_a$	25	33	25	5.5	33.3	75	100
$\%Plants_t$	35	67	75	5.5	66.7	25	0
$\%WW_{a,p}$	0	0	0	0	0	0	0
$\%WW_{a,s}$	100	100	100	100	100	100	100
$\%WW_{a,t}$	0	0	0	0	0	0	0

%COD_p	100	100	100	100	100	100	100
%COD_s	42	100	100	77	100	100	100

Pulp and Paper. Wastewater treatment for the pulp and paper industry typically includes neutralization, screening, sedimentation, and flotation/hydrocycloning to remove solids (World Bank 1999, Nemerow and Dasgupta 1991). Secondary treatment (storage, settling, and biological treatment) mainly consists of lagooning. In determining the percent that degrades anaerobically, both primary and secondary treatment were considered. In the United States, primary treatment is focused on solids removal, equalization, neutralization, and color reduction (EPA 1993). The vast majority of pulp and paper mills with on-site treatment systems use mechanical clarifiers to remove suspended solids from the wastewater. About 10 percent of pulp and paper mills with treatment systems use settling ponds for primary treatment and these are more likely to be located at mills that do not perform secondary treatment (EPA 1993). However, because the vast majority of primary treatment operations at U.S. pulp and paper mills use mechanical clarifiers, and less than 10 percent of pulp and paper wastewater is managed in primary settling ponds that are not expected to have anaerobic conditions, negligible emissions are assumed to occur during primary treatment.

Approximately 42 percent of the BOD passes on to secondary treatment, which consists of activated sludge, aerated stabilization basins, or non-aerated stabilization basins. No anaerobic activity is assumed to occur in activated sludge systems or aerated stabilization basins (note: although IPCC recognizes that some CH_4 can be emitted from anaerobic pockets, they recommend an MCF of zero). However, about 25 percent of the wastewater treatment systems used in the United States are non-aerated stabilization basins. These basins are typically 10 to 25 feet deep. These systems are classified as anaerobic deep lagoons (MCF = 0.8).

A time series of CH_4 emissions for 1990 through 2001 was developed based on production figures reported in the Lockwood-Post Directory (Lockwood-Post 2002). Published data from the American Forest and Paper Association, data published by Paper Loop, and other published statistics were used to estimate production for 2002 through 2009 (Pulp and Paper 2005, 2006, and monthly reports from 2003 through 2008; Paper 360° 2007). The overall wastewater outflow was estimated to be 85 m^3/metric ton, and the average BOD concentrations in raw wastewater was estimated to be 0.4 gram BOD/liter (EPA 1997b, EPA 1993, World Bank 1999).

Meat and Poultry Processing. The meat and poultry processing industry makes extensive use of anaerobic lagoons in sequence with screening, fat traps and dissolved air flotation when treating wastewater on site. About 33 percent of meat processing operations (EPA 2002) and 25 percent of poultry processing operations (U.S. Poultry 2006) perform on-site treatment in anaerobic lagoons. The IPCC default B_o of 0.25 kg CH_4/kg COD and default MCF of 0.8 for anaerobic lagoons were used to estimate the CH_4 produced from these on-site treatment systems. Production data, in carcass weight and live weight killed for the meat and poultry industry, were obtained from the USDA Agricultural Statistics Database and the Agricultural Statistics Annual Reports (USDA 2010). Data collected by EPA's Office of Water provided estimates for wastewater flows into anaerobic lagoons: 5.3 and 12.5 m^3/metric ton for meat and poultry production (live weight killed), respectively (EPA 2002). The loadings are 2.8 and 1.5 g BOD/liter for meat and poultry, respectively.

Vegetables, Fruits, and Juices Processing. Treatment of wastewater from fruits, vegetables, and juices processing includes screening, coagulation/settling, and biological treatment (lagooning). The flows are frequently seasonal, and robust treatment systems are preferred for on-site treatment. Effluent is suitable for discharge to the sewer. This industry is likely to use lagoons intended for aerobic operation, but the large seasonal loadings may develop limited anaerobic zones. In addition, some anaerobic lagoons may also be used (Nemerow and Dasgupta 1991). Consequently, 4.2 percent of these wastewater organics are assumed to degrade anaerobically. The IPCC default B_o of 0.25 kg CH_4/kg COD and default MCF of 0.8 for anaerobic treatment were used to estimate the CH_4 produced from these on-site treatment systems. The USDA National Agricultural Statistics Service (USDA 2010) provided production data for potatoes, other vegetables, citrus fruit, non-citrus fruit, and grapes processed for wine. Outflow and BOD data, presented in Table 8-13, were obtained from EPA (1974) for potato, citrus fruit, and apple processing, and from EPA (1975) for all other sectors.

Table 8-13. Wastewater Flow (m^3/ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production

Commodity	Wastewater Outflow (m^3/ton)	BOD (g/L)
Vegetables		
Potatoes	10.27	1.765
Other Vegetables	8.74	0.801

Fruit		
Apples	3.66	1.371
Citrus	10.11	0.317
Non-citrus	12.42	1.204
Grapes (for wine)	2.78	1.831

Ethanol Production. Ethanol, or ethyl alcohol, is produced primarily for use as a fuel component, but is also used in industrial applications and in the manufacture of beverage alcohol. Ethanol can be produced from the fermentation of sugar-based feedstocks (e.g., molasses and beets), starch- or grain-based feedstocks (e.g., corn, sorghum, and beverage waste), and cellulosic biomass feedstocks (e.g., agricultural wastes, wood, and bagasse). Ethanol can also be produced synthetically from ethylene or hydrogen and carbon monoxide. However, synthetic ethanol comprises only about 2 percent of ethanol production, and although the Department of Energy predicts cellulosic ethanol to greatly increase in the coming years, currently it is only in an experimental stage in the United States. According to the Renewable Fuels Association, 82 percent of ethanol production facilities use corn as the sole feedstock and 7 percent of facilities use a combination of corn and another starch-based feedstock. The fermentation of corn is the principal ethanol production process in the United States and is expected to increase through 2012, and potentially more; therefore, emissions associated with wastewater treatment at starch-based ethanol production facilities were estimated (ERG 2006).

Ethanol is produced from corn (or other starch-based feedstocks) primarily by two methods: wet milling and dry milling. Historically, the majority of ethanol was produced by the wet milling process, but now the majority is produced by the dry milling process. The wastewater generated at ethanol production facilities is handled in a variety of ways. Dry milling facilities often combine the resulting evaporator condensate with other process wastewaters, such as equipment wash water, scrubber water, and boiler blowdown and anaerobically treat this wastewater using various types of digesters. Wet milling facilities often treat their steepwater condensate in anaerobic systems followed by aerobic polishing systems. Wet milling facilities may treat the stillage (or processed stillage) from the ethanol fermentation/distillation process separately or together with steepwater and/or wash water. CH_4 generated in anaerobic digesters is commonly collected and either flared or used as fuel in the ethanol production process (ERG 2006).

Available information was compiled from the industry on wastewater generation rates, which ranged from 1.25 gallons per gallon ethanol produced (for dry milling) to 10 gallons per gallon ethanol produced (for wet milling) (Ruocco 2006a,b; Merrick 1998; Donovan 1996; and NRBP 2001). COD concentrations were also found to be about 3 g/L (Ruocco 2006a; Merrick 1998; White and Johnson 2003). The amount of wastewater treated anaerobically was estimated, along with how much of the CH_4 is recovered through the use of biomethanators (ERG 2006). CH_4 emissions were then estimated as follows:

$$\text{Methane} = [\text{Production} \times \text{Flow} \times \text{COD} \times 3.785 \times ([\%\text{Plants}_o \times \%\text{WW}_{a,p} \times \%\text{COD}_p] + [\%\text{Plants}_a \times \%\text{WW}_{a,s} \times \%\text{COD}_s] + [\%\text{Plants}_t \times \%\text{WW}_{a,t} \times \%\text{COD}_s]) \times B_o \times \text{MCF} \times \%\ \text{Not Recovered}] + [\text{Production} \times \text{Flow} \times 3.785 \times \text{COD} \times ([\%\text{Plants}_o \times \%\text{WW}_{a,p} \times \%\text{COD}_p] + [\%\text{Plants}_a \times \%\text{WW}_{a,s} \times \%\text{COD}_s] + [\%\text{Plants}_t \times \%\text{WW}_{a,t} \times \%\text{COD}_s]) \times B_o \times \text{MCF} \times (\%\ \text{Recovered}) \times (1\text{-DE})] \text{ x } 1/10\text{^}9$$

Where:

Production = gallons ethanol produced (wet milling or dry milling)
Flow = gallons wastewater generated per gallon ethanol produced (1.25 dry milling, 10 wet milling)
COD = COD concentration in influent (3 g/l)
3.785 = conversion, gallons to liters
$\%\text{Plants}_o$ = percent of plants with onsite treatment (100%)
$\%\text{WW}_{a,p}$ = percent of wastewater treated anaerobically in primary treatment (0%)
$\%\text{COD}_p$ = percent of COD entering primary treatment (100%)
$\%\text{Plants}_a$ = percent of plants with anaerobic secondary treatment (33.3% wet, 75% dry)
$\%\text{Plants}_t$ = percent of plants with other secondary treatment (66.7% wet, 25% dry)
$\%\text{WW}_{a,s}$ = percent of wastewater treated anaerobically in anaerobic secondary treatment (100%)
$\%\text{WW}_{a,t}$ = percent of wastewater treated anaerobically in other secondary treatment (0%)
$\%\text{COD}_s$ = percent of COD entering secondary treatment (100%)

B_o = maximum methane producing capacity (0.25 g CH_4/g COD)
MCF = methane conversion factor (0.8 for anaerobic systems)
% Recovered = percent of wastewater treated in system with emission recovery
% Not Recovered = 1 - percent of wastewater treated in system with emission recovery
DE = destruction efficiency of recovery system (99%)
1/10^9 = conversion factor, g to Gg

A time series of CH_4 emissions for 1990 through 2009 was developed based on production data from the Renewable Fuels Association (RFA 2010).

Petroleum Refining. Petroleum refining wastewater treatment operations produce CH_4 emissions from anaerobic wastewater treatment. The wastewater inventory section includes CH_4 emissions from petroleum refining wastewater treated on site under intended or unintended anaerobic conditions. Most facilities use aerated biological systems, such as trickling filters or rotating biological contactors; these systems can also exhibit anaerobic conditions that can result in the production of CH_4. Oil/water separators are used as a primary treatment method; however, it is unlikely that any COD is removed in this step.

Available information from the industry was compiled. The wastewater generation rate, from CARB (2007) and Timm (1985), was determined to be 35 gallons per barrel of finished product. An average COD value in the wastewater was estimated at 0.45 kg/m^3 (Benyahia et al. 2006).

The equation used to calculate CH_4 generation at petroleum refining wastewater treatment systems is presented below:

$$\text{Methane} = \text{Flow} \times \text{COD} \times B_o \times \text{MCF}$$

Where:

Flow = Annual flow treated through anaerobic treatment system (m^3/year)
COD = COD loading in wastewater entering anaerobic treatment system (kg/m^3)
B_o = maximum methane producing potential of industrial wastewater (default value of 0.25 kg CH_4 /kg COD)
MCF = methane conversion factor (0.3)

A time series of CH_4 emissions for 1990 through 2009 was developed based on production data from the Energy Information Association (EIA 2010).

Domestic Wastewater N_2O Emission Estimates

N_2O emissions from domestic wastewater (wastewater treatment) were estimated using the IPCC (2006) methodology, including calculations that take into account N removal with sewage sludge, non-consumption and industrial wastewater N, and emissions from advanced centralized wastewater treatment plants:

- In the United States, a certain amount of N is removed with sewage sludge, which is applied to land, incinerated, or landfilled (N_{SLUDGE}). The N disposal into aquatic environments is reduced to account for the sewage sludge application.
- The IPCC methodology uses annual, per capita protein consumption (kg protein/[person-year]). For this inventory, the amount of protein available to be consumed is estimated based on per capita annual food availability data and its protein content, and then adjusts that data using a factor to account for the fraction of protein actually consumed.
- Small amounts of gaseous nitrogen oxides are formed as by-products in the conversion of nitrate to N gas in anoxic biological treatment systems. Approximately 7 grams N_2O is generated per capita per year if wastewater treatment includes intentional nitrification and denitrification (Scheehle and Doorn 2001). Analysis of the 2004 CWNS shows that plants with denitrification as one of their unit operations serve a population of 2.4 million people. Based on an emission factor of 7 grams per capita per year, approximately 21.2 metric tons of additional N_2O may have been emitted via denitrification in 2004. Similar analyses were completed for each year in the Inventory using data from CWNS on the amount of wastewater in centralized systems treated in denitrification units. Plants without intentional nitrification/denitrification are assumed to generate 3.2 grams N_2O per capita

per year.

N_2O emissions from domestic wastewater were estimated using the following methodology:

$$N_2O_{TOTAL} = N_2O_{PLANT} + N_2O_{EFFLUENT}$$

$$N_2O_{PLANT} = N_2O_{NIT/DENIT} + N_2O_{WOUT\ NIT/DENIT}$$

$$N_2O_{NIT/DENIT} = [(US_{POPND}) \times EF_2 \times F_{IND\text{-}COM}] \times 1/10^{\wedge}9$$

$$N_2O_{WOUT\ NIT/DENIT} = \{[(US_{POP} \times WWTP) - US_{POPND}] \times F_{IND\text{-}COM} \times EF_1\} \times 1/10^{\wedge}9$$

$$N_2O_{EFFLUENT} = \{[((US_{POP} - (0.9 \times US_{POPND})) \times Protein \times F_{NPR} \times F_{NON\text{-}CON} \times F_{IND\text{-}COM}) - N_{SLUDGE}] \times EF_3 \times 44/28\} \times 1/10^{\wedge}6$$

where,

N_2O_{TOTAL} = Annual emissions of N_2O (Gg)
N_2O_{PLANT} = N_2O emissions from centralized wastewater treatment plants (Gg)
$N_2O_{NIT/DENIT}$ = N_2O emissions from centralized wastewater treatment plants with nitrification/denitrification (Gg)
$N_2O_{WOUT\ NIT/DENIT}$ = N_2O emissions from centralized wastewater treatment plants without nitrification/denitrification (Gg)
$N_2O_{EFFLUENT}$ = N_2O emissions from wastewater effluent discharged to aquatic environments (Gg)
US_{POP} = U.S. population
US_{POPND} = U.S. population that is served by biological denitrification (from CWNS)
WWTP = Fraction of population using WWTP (as opposed to septic systems)
EF_1 = Emission factor (3.2 g N_2O/person-year) – plant with no intentional denitrification
EF_2 = Emission factor (7 g N_2O/person-year) – plant with intentional denitrification
Protein = Annual per capita protein consumption (kg/person/year)
F_{NPR} = Fraction of N in protein, default = 0.16 (kg N/kg protein)
$F_{NON\text{-}CON}$ = Factor for non-consumed protein added to wastewater (1.4)
$F_{IND\text{-}COM}$ =Factor for industrial and commercial co-discharged protein into the sewer system (1.25)
N_{SLUDGE} = N removed with sludge, kg N/yr
EF_3 = Emission factor (0.005 kg N_2O -N/kg sewage-N produced) – from effluent
0.9 = Amount of nitrogen removed by denitrification systems
44/28 = Molecular weight ratio of N_2O to N_2

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. The fraction of the U.S. population using wastewater treatment plants is based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Survey (U.S. Census 2009). Data for intervening years were obtained by linear interpolation. The emission factor (EF_1) used to estimate emissions from wastewater treatment was taken from IPCC (2006). Data on annual per capita protein intake were provided by U.S. Department of Agriculture Economic Research Service (USDA 2009). Protein consumption data for 2005 through 2009 were extrapolated from data for 1990 through 2004. Table 8-14 presents the data for U.S. population and average protein intake. An emission factor to estimate emissions from effluent (EF_3) has not been specifically estimated for the United States, thus the default IPCC value (0.005 kg N_2O-N/kg sewage-N produced) was applied. The fraction of N in protein (0.16 kg N/kg protein) was also obtained from IPCC (2006). The factor for non-consumed protein and the factor for industrial and commercial co-discharged protein were obtained from IPCC (2006). Sludge generation was obtained from EPA (1999) for 1988, 1996, and 1998 and from Beecher et al. (2007) for 2004. Intervening years were interpolated, and estimates for 2005 through 2009 were forecasted from the rest of the time series. An estimate for the N removed as sludge (N_{SLUDGE}) was obtained by determining the amount of sludge disposed by incineration, by land application (agriculture or other), through surface disposal, in landfills, or through ocean dumping. In 2009, 271 Gg N was removed with sludge.

Table 8-14. U.S. Population (Millions), Available Protein (kg/person-year), and Protein Consumed (kg/person-year)

Year	Population	Available Protein	Protein Consumed
1990	254	38.7	29.6

2000	286	41.3	31.6
2005	300	41.7	32.1
2006	303	41.9	32.1
2007	306	42.1	32.2
2008	309	42.2	32.4
2009	311	42.4	32.5

Source: U.S. Census Bureau 2010, USDA 2009.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with both the 2009 CH_4 and N_2O emission estimates from wastewater treatment and discharge was calculated using the IPCC Good Practice Guidance Tier 2 methodology (2000). Uncertainty associated with the parameters used to estimate CH_4 emissions include that of numerous input variables used to model emissions from domestic wastewater, and wastewater from pulp and paper manufacture, meat and poultry processing, fruits and vegetable processing, ethanol production, and petroleum refining. Uncertainty associated with the parameters used to estimate N_2O emissions include that of sewage sludge disposal, total U.S. population, average protein consumed per person, fraction of N in protein, non-consumption nitrogen factor, emission factors per capita and per mass of sewage-N, and for the percentage of total population using centralized wastewater treatment plants.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 8-15. CH_4 emissions from wastewater treatment were estimated to be between 15.3 and 35.9 Tg CO_2 Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 37 percent below to 47 percent above the 2009 emissions estimate of 24.5 Tg CO_2 Eq. N_2O emissions from wastewater treatment were estimated to be between 1.2 and 9.7 Tg CO_2 Eq., which indicates a range of approximately 76 percent below to 93 percent above the actual 2009 emissions estimate of 5.0 Tg CO_2 Eq.

Table 8-15. Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Wastewater Treatment (Tg CO_2 Eq. and Percent)

Source	**Gas**	**2009 Emission Estimate (Tg CO2 Eq.)**	**Uncertainty Range Relative to Emission Estimate[a]**			
			(Tg CO2 Eq.)		**(%)**	
			Lower Bound	**Upper Bound**	**Lower Bound**	**Upper Bound**
Wastewater Treatment	**CH_4**	**24.5**	**15.3**	**35.9**	**-37%**	**+47%**
Domestic	CH_4	16.0	7.6	26.6	-52%	+66%
Industrial	CH_4	8.5	5.1	13.1	-41%	+54%
Wastewater Treatment	**N_2O**	**5.0**	**1.2**	**9.7**	**-76%**	**+93%**

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A QA/QC analysis was performed on activity data, documentation, and emission calculations. This effort included a Tier 1 analysis, including the following checks:

- Checked for transcription errors in data input;
- Ensured references were specified for all activity data used in the calculations;
- Checked a sample of each emission calculation used for the source category;
- Checked that parameter and emission units were correctly recorded and that appropriate conversion factors were used;
- Checked for temporal consistency in time series input data for each portion of the source category;
- Confirmed that estimates were calculated and reported for all portions of the source category and for all years;
- Investigated data gaps that affected emissions estimates trends; and

- Compared estimates to previous estimates to identify significant changes.

All transcription errors identified were corrected. The QA/QC analysis did not reveal any systemic inaccuracies or incorrect input values.

Planned Improvements Discussion

The methodology to estimate CH_4 emissions from domestic wastewater treatment currently utilizes estimates for the percentage of centrally treated wastewater that is treated by aerobic systems and anaerobic systems. These data come from the 1992, 1996, 2000, and 2004 CWNS. The question of whether activity data for wastewater treatment systems are sufficient across the timeseries to further differentiate aerobic systems with the potential to generate small amounts of CH_4 (aerobic lagoons) versus other types of aerobic systems, and to differentiate between anaerobic systems to allow for the use of different MCFs for different types of anaerobic treatment systems, continues to be explored. Recently available CWNS data for 2008 also is being evaluated for incorporation into the inventory. Due to significant changes in format, this dataset was unable to be included in the domestic wastewater calculations for the current Inventory. However, EPA continues to evaluate ways to incorporate the updated data into future years of the Inventory.

Currently, it is assumed that all aerobic systems are well managed and produce no CH_4 and that all anaerobic systems have an MCF of 0.8. Efforts to obtain better data reflecting emissions from various types of municipal treatment systems are currently being pursued.

A review of other industrial wastewater treatment sources for those industries believed to discharge significant loads of BOD and COD has been ongoing. Food processing industries have the highest potential for CH_4 generation due to the waste characteristics generated, and the greater likelihood to treat the wastes anaerobically. However, in all cases there is dated information available on U.S. treatment operations for these industries. A review of the organic chemicals industry was conducted in April 2010, during which only 1987 data was readily identified. It was concluded that current industry-level treatment system information is very difficult to obtain, as is time series data. Based on the 1987 data, emissions from this source are small and are not a likely industry category for significant CH_4 emissions. Therefore, this industry has not been included in the Inventory and there are no near future plans to do so. Similarly, the seafood processing industry was reviewed to estimate its potential to generate CH_4. Due to minimal anaerobic wastewater treatment operations at processing facilities, this industry was not selected for inclusion in the Inventory. Other industries will be reviewed as necessary for inclusion in future years of the Inventory.

Available data will be reviewed regarding anaerobic treatment at petroleum refineries. If necessary, the %TA for this industry will be revised accordingly. Currently, all petroleum plants are assumed to have anaerobic treatment.

With respect to estimating N_2O emissions, the default emission factor for indirect N_2O from wastewater effluent and direct N_2O from centralized wastewater treatment facilities has a high uncertainty. Current research is being conducted by the Water Environment Research Foundation (WERF) to measure N_2O emissions from municipal treatment systems. Such data will be reviewed as they are available to determine if a country-specific N_2O emission factor can or should be developed, or if alternate emission factors should be used. EPA expects WERF to publish a final N_2O generation report by the end of 2011. In addition, WERF recently conducted a study of greenhouse gas emissions from septic systems located in California. This study concluded that the emission rate for methane and nitrous oxide were 10.7 and 0.20 g/capita-d, respectively. EPA is currently reviewing the results of this study to determine if the systems evaluated are representative of U.S. operations and if a country-specific factor for septic systems can be introduced into the inventory. The effect would be to lower current estimates of CH_4 emissions by about half, and to include N_2O emission estimates where previously none were calculated. In addition, more investigation of new study results will be used to evaluate the method used to calculate N_2O emissions associated with effluent and whether septic systems are appropriately included in the calculation.

In addition, the estimate of N entering municipal treatment systems is under review. The factor that accounts for non-sewage N in wastewater (bath, laundry, kitchen, industrial components) also has a high uncertainty. Obtaining data on the changes in average influent N concentrations to centralized treatment systems over the time series would improve the estimate of total N entering the system, which would reduce or eliminate the need for other factors for non-consumed protein or industrial flow. The dataset previously provided by the National Association of Clean Water Agencies (NACWA) was reviewed to determine if it was representative of the larger population of centralized treatment plants for potential inclusion into the inventory. However, this limited dataset was not representative of the number of systems by state or the service populations served in the United States, and therefore could not be incorporated into the inventory methodology. Additional data sources will continue to be researched with the goal of improving the uncertainty of the estimate of N entering municipal treatment systems.

8.3. Composting (IPCC Source Category 6D)

Composting of organic waste, such as food waste, garden (yard) and park waste, and sludge, is common in the United States. Advantages of composting include reduced volume in the waste material, stabilization of the waste, and destruction of pathogens in the waste material. The end products of composting, depending on its quality, can be recycled as fertilizer and soil amendment, or be disposed in a landfill.

Composting is an aerobic process and a large fraction of the degradable organic carbon in the waste material is converted into carbon dioxide (CO_2). Methane (CH_4) is formed in anaerobic sections of the compost, but it is oxidized to a large extent in the aerobic sections of the compost. Anaerobic sections are created in composting piles when there is excessive moisture or inadequate aeration (or mixing) of the compost pile. The estimated CH_4 released into the atmosphere ranges from less than 1 percent to a few percent of the initial C content in the material (IPCC 2006). Composting can also produce nitrous oxide (N_2O) emissions. The range of the estimated emissions varies from less than 0.5 percent to 5 percent of the initial nitrogen content of the material (IPCC 2006).

From 1990 to 2009, the amount of material composted in the United States has increased from 3,810 Gg to 19,857 Gg, an increase of approximately 421 percent. From 2000 to 2009, the amount of material composted in the United States has increased by approximately 33 percent. Emissions of CH_4 and N_2O from composting have increased by the same percentage (see Table 8-16 and Table 8-17). In 2009, CH_4 emissions from composting were 1.7 Tg CO_2 Eq. (79 Gg), and N_2O emissions from composting were 1.8 Tg CO_2 Eq. (6 Gg). The wastes that are composted include primarily yard trimmings (grass, leaves, and tree and brush trimmings) and food scraps from residences and commercial establishments (such as grocery stores, restaurants, and school and factory cafeterias). The composting waste quantities reported here do not include backyard composting. The growth in composting is attributable primarily to two factors: (1) steady growth in population and residential housing, and (2) state and local governments started enacting legislation that discouraged the disposal of yard trimmings in landfills. In 1992, 11 states and the District of Columbia had legislation in effect that banned or discouraged disposal of yard trimmings in landfills. In 2005, 21 states and the District of Columbia, representing about 50 percent of the nation's population, had enacted such legislation (EPA 2008).

Table 8-16. CH_4 and N_2O Emissions from Composting (Tg CO_2 Eq.)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N_2O	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	**0.7**	**2.7**	**3.3**	**3.3**	**3.5**	**3.5**	**3.5**

Table 8-17. CH_4 and N_2O Emissions from Composting (Gg)

Activity	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**
CH_4	15	60	75	75	79	80	79
N_2O	1	4	6	6	6	6	6

Methodology

CH_4 and N_2O emissions from composting depend on factors such as the type of waste composted, the amount and type of supporting material (such as wood chips and peat) used, temperature, moisture content and aeration during the process.

The emissions shown in Table 8-16 and Table 8-17 were estimated using the IPCC default (Tier 1) methodology (IPCC 2006), which is the product of an emission factor and the mass of organic waste composted (note: no CH_4 recovery is expected to occur at composting operations):

$$E_i = M \times EF_i$$

where,

E_i = CH_4 or N_2O emissions from composting, Gg CH_4 or N_2O,
M = mass of organic waste composted in Gg,
EF_i = emission factor for composting, 4 g CH_4/kg of waste treated (wet basis) and 0.3 g N_2O/kg of waste treated (wet basis), and
i = designates either CH_4 or N_2O.

Estimates of the quantity of waste composted (M) are presented in Table 8-18. Estimates of the quantity composted for 1990 and 1995 were taken from the *Characterization of Municipal Solid Waste in the United States: 1996 Update* (Franklin Associates 1997); estimates of the quantity composted for 2000, 2005, 2006, 2007, and 2008 were taken from EPA's *Municipal Solid Waste In The United States: 2008 Facts and Figures* (EPA 2009); estimates of the quantity composted for 2009 were calculated using the 2008 quantity composted.

Table 8-18: U.S. Waste Composted (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Waste Composted	3,810	14,923	18,643	18,852	19,695	20,049	19,857

Source: Franklin Associates 1997 and EPA 2009.

Uncertainty and Time-Series Consistency

The estimated uncertainty from the 2006 IPCC Guidelines is ±50 percent for the Tier 1 methodology. Emissions from composting in 2009 were estimated to be between 1.8 and 5.3 Tg CO_2 Eq., which indicates a range of 50 percent below to 50 percent above the actual 2009 emission estimate of 3.5 Tg CO_2 Eq. (see Table 8-19).

Table 8-19 : Tier 1 Quantitative Uncertainty Estimates for Emissions from Composting (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO2 Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Composting	CH_4, N_2O	3.5	1.8	5.3	-50%	+50%

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

For future Inventories, additional efforts will be made to improve the estimates of CH_4 and N_2O emissions from composting. For example, a literature search may be conducted to determine if emission factors specific to various composting systems and composted materials are available.

8.4. Waste Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, waste generating and handling processes are also sources of indirect greenhouse gas emissions. Total emissions of NO_x, CO, and NMVOCs from waste sources for the years 1990 through 2009 are provided in Table 8-20.

Table 8-20: Emissions of NO_x, CO, and NMVOC from Waste (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
NO_x	**+**	**2**	**2**	**2**	**2**	**2**	**2**
Landfills	+	2	2	2	2	2	2
Wastewater Treatment	+	+	+	+	+	+	+
Miscellaneous[a]	+	+	+	+	+	+	0
CO	**1**	**8**	**7**	**7**	**7**	**7**	**7**
Landfills	1	7	6	6	6	6	6
Wastewater Treatment	+	1	+	+	+	+	+
Miscellaneous[a]	+	+	+	+	+	+	+
NMVOCs	**673**	**119**	**114**	**113**	**111**	**109**	**76**
Wastewater Treatment	57	51	49	49	48	47	33
Miscellaneous[a]	557	46	43	43	42	41	29
Landfills	58	22	22	21	21	21	14

[a] Miscellaneous includes TSDFs (Treatment, Storage, and Disposal Facilities under the Resource Conservation and Recovery Act [42 U.S.C. § 6924, SWDA § 3004]) and other waste categories.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emission estimates of these gases were provided by sector, using a “top down” estimating procedure—emissions were calculated either for individual sources or for many sources combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual source categories from various agencies. Depending on the source category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Uncertainty and Time-Series Consistency

No quantitative estimates of uncertainty were calculated for this source category. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009.

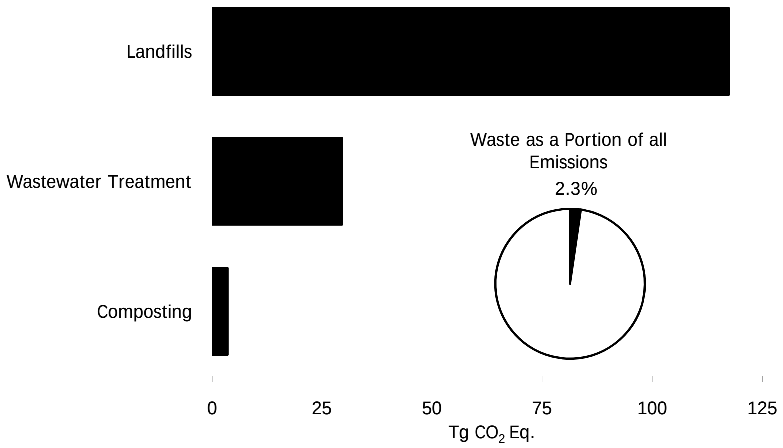

Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

9. Other

The United States does not report any greenhouse gas emissions under the Intergovernmental Panel on Climate Change (IPCC) "Other" sector.

10. Recalculations and Improvements

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is *good practice* to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors."

The results of all methodological changes and historical data updates are presented in this section; detailed descriptions of each recalculation are contained within each source's description found in this report, if applicable. Table 10-1 summarizes the quantitative effect of these changes on U.S. greenhouse gas emissions and Table 10-2 summarizes the quantitative effect on net CO_2 flux to the atmosphere, both relative to the previously published U.S. Inventory (i.e., the 1990 through 2008 report). These tables present the magnitude of these changes in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.).

The Recalculations Discussion section of each source presents the details of each recalculation. In general, when methodological changes have been implemented, the entire time series (i.e., 1990 through 2008) has been recalculated to reflect the change, per IPCC (2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies.

The following emission sources, which are listed in descending order of absolute average annual change in emissions between 1990 and 2008, underwent some of the most important methodological and historical data changes. A brief summary of the recalculations and/or improvements undertaken is provided for each emission source.

- *Natural Gas Systems (CH_4).* For the current Inventory, methodologies for gas well cleanups and condensate storage tanks were revised, and new data sources for centrifugal compressors with wet seals, unconventional gas well completions, and unconventional gas well workovers were used, relative to the previous Inventory. The net effect of these changes was an increase in total CH_4 emissions from natural gas systems of between 46.5 and 119.7 percent each year between 1990 and 2008, resulting in an overall annual average increase of 79.3 Tg CO_2 Eq. (66.4 percent). The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of unconventional gas well completions and workovers.

- *Landfills (CH_4)* Changes in CH_4 emissions from Landfills relative to the previous Inventory resulted from improvements made to better associate flares with the correct landfills or Landfill Gas to Energy projects across the nation. In addition, steps were also taken to further characterize the food waste decay rate. A weighted component-specific decay rate for food waste of 0.156 yr^{-1} was used in the current Inventory, replacing the previous Inventory's default food waste decay rate of 0.185 yr^{-1} These revisions impacted emission estimates for the entire time series and resulted in an average annual decrease of 8.3 Tg CO_2 Eq. (6.5 percent) in CH_4 emissions from Landfills for the period 1990 through 2008.

- *Manure Management (CH_4).* Changes in CH_4 emissions from Manure Management relative to the previous Inventory resulted from several updates. Volatile solid production rates for all animal types were updated based on data from the USDA and EPA's Cattle Enteric Fermentation Model. In addition, USDA data on swine were re-categorized, which changed the typical animal mass for two categories. These changes impacted emission estimates for the entire time series and resulted in an average annual increase of 3.5 Tg CO_2 Eq. (9.4 percent) in CH_4 emissions from Manure Management across the entire time series relative to the previous Inventory.

- *Agricultural Soil Management (N_2O).* Changes in N_2O emissions from Agricultural Soil Management relative to the previous Inventory resulted from methodological changes for estimating grassland areas and livestock manure nitrogen. These recalculations have opposing effects on emissions; grassland area was reduced, resulting in lower emissions, and livestock manure nitrogen increased, resulting in higher emissions. These changes affected the entire time series, resulting in an average annual reduction in N_2O emissions of 3.2 Tg CO_2 Eq. (1.5 percent) for the period 1990 through 2008 relative to the previous Inventory.

- *Iron and Steel Production & Metallurgical Coke Production (CO_2).* A calculation error in the previous Inventory regarding coal tar production and coke breeze production estimates was corrected for the current Inventory, resulting in an average annual decrease in CO_2 emissions from Iron and Steel Production & Metallurgical Coke Production of 2.2 Tg CO_2 Eq. (2.7 percent) for the period 1990 through 2008.
- *Non-Energy Uses of Fossil Fuels (CO_2).* Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 resulted in changes to CO_2 emissions from Non-Energy Uses of Fossil Fuels for 2003 through 2008 relative to the previous Inventory. Adjustments were made to the entire MECS time series to remove scrap tire consumption for use as a fuel, which is associated with the Waste Incineration chapter. In addition, emissions from synthetic rubber were revised across the entire time series. These changes impacted emission estimates from 1990 through 2008 resulting in an average annual decrease in CO_2 emissions of 1.4 Tg CO_2 Eq. (1.0 percent) across the entire time series.
- *Petroleum Systems (CH_4).* Well completion venting, well drilling, and offshore platform activity factors were updated relative to the previous Inventory from existing data sources from 1990 onward, and the emission factor for venting from fixed roof storage tanks in the crude oil production segment was increased to reflect the occurrence of gas venting through storage tanks. These changes affected the entire time series from Petroleum Systems, resulting in an average annual increase in CH_4 emissions of 1.3 Tg CO_2 Eq. (4.3 percent) for the period 1990 through 2008 relative to the previous report.
- *Nitric Acid Production (N_2O).* Changes in N_2O emission from Nitric Acid Production relative to the previous Inventory resulted from updated information on abatement technologies in use at production facilities and revised production data from the U.S. Census Bureau. These changes resulted in an average annual decrease in N_2O emissions of 1.3 Tg CO_2 Eq. (6.7 percent) across the entire time series relative to the previous report.
- *Electrical Transmission and Distribution (SF_6).* SF_6 emission estimates for the period 1990 through 2008 were updated relative to the previous Inventory based on (1) new data from EPA's SF_6 Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. In addition, the method for estimating potential emissions from the sector was updated for the current Inventory to assume that all SF_6 purchased by equipment manufacturers is either emitted or sent to utilities. These changes affected the entire time series, resulting in an average annual increase of 1.2 Tg CO_2 Eq. (6.6 percent) for the period 1990 through 2008 relative to the previous report.
- *Forestland Remaining Forestland (C Sink).* Changes to the estimated carbon stored in Forestland Remaining Forestland stemmed from recent additions to the Forest Inventory and Analysis Database (FIADB). Newer annual inventory data for most states including Oklahoma, California, Oregon, and Washington were added. Some older periodic inventories for some southern states were also updated. These changes resulted in an average annual increase in carbon stored in forestland of 6.8 Tg CO_2 Eq. (2.4 percent) for the period 1990 through 2008 relative to the previous inventory report.

Table 10-1: Revisions to U.S. Greenhouse Gas Emissions (Tg CO2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008
CO_2	**(1.1)**	**(2.2)**	**5.3**	**3.9**	**(0.2)**	**0.2**
Fossil Fuel Combustion	2.7	1.5	(0.1)	0.3	(0.3)	(6.8)
Electricity Generation	+	+	+	NC	+	(2.6)
Transportation	0.2	+	1.3	1.4	0.2	4.7
Industrial	1.0	(1.1)	(2.5)	(2.5)	(0.2)	(16.4)
Residential	(0.8)	(0.5)	(0.5)	(0.5)	0.7	5.5
Commercial	2.3	3.2	2.3	2.6	2.0	4.7
U.S. Territories	NC	NC	(0.7)	(0.7)	(3.0)	(2.7)
Non-Energy Use of Fuels	(1.0)	(1.2)	6.9	4.2	1.9	6.8
Iron and Steel Production & Metallurgical Coke Production	(3.0)	(2.2)	(1.8)	(1.8)	(1.8)	(3.0)
Natural Gas Systems	0.3	0.5	0.4	1.2	0.2	2.9
Cement Production	NC	(0.8)	(0.7)	(0.8)	(0.7)	(0.6)
Incineration of Waste	(0.1)	(0.2)	(0.2)	(0.2)	(0.6)	(1.0)

Ammonia Production and Urea Consumption	NC	NC	NC	NC	0.1	0.2
Lime Production	NC	NC	NC	NC	NC	NC
Cropland Remaining Cropland	NC	NC	NC	NC	(0.1)	1.0
Limestone and Dolomite Use	NC	NC	NC	NC	NC	(0.3)
Soda Ash Production and Consumption	NC	NC	NC	NC	NC	NC
Aluminum Production	NC	NC	NC	NC	NC	NC
Petrochemical Production	NC	NC	NC	NC	NC	NC
Carbon Dioxide Consumption	NC	NC	NC	+	NC	NC
Titanium Dioxide Production	NC	NC	NC	NC	NC	NC
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	0.1
Phosphoric Acid Production	NC	NC	NC	NC	NC	+
Zinc Production	(0.3)	(0.1)	0.6	0.6	0.7	0.8
Lead Production	0.2	0.3	0.3	0.3	0.3	0.3
Petroleum Systems	+	+	+	+	+	+
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Land Use, Land-Use Change, and Forestry (Sink)[a]	*47.9*	*87.7*	*(106.1)*	*(105.2)*	*(105.5)*	*(100.1)*
Biomass - Wood[a]	*NC*	*NC*	*NC*	*(4.0)*	*(4.1)*	*(0.1)*
International Bunker Fuels[a]	*+*	*+*	*(0.8)*	*(0.7)*	*0.6*	*(1.5)*
Biomass - Ethanol[a]	*0.1*	*0.2*	*0.4*	*0.5*	*0.7*	*1.4*
CH_4	**61.5**	**73.9**	**78.3**	**103.9**	**95.4**	**109.1**
Natural Gas Systems	60.3	78.6	86.8	114.6	105.7	115.4
Enteric Fermentation	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Landfills	(1.9)	(9.0)	(13.1)	(15.3)	(15.2)	(10.4)
Coal Mining	NC	NC	NC	+	(0.2)	(0.5)
Manure Management	2.4	3.8	4.3	4.4	4.9	4.4
Petroleum Systems	1.5	1.3	1.1	1.1	1.2	1.1
Wastewater Treatment	+	+	+	+	+	0.2
Forest Land Remaining Forest Land	+	+	+	+	+	+
Rice Cultivation	NC	NC	NC	NC	NC	NC
Stationary Combustion	+	+	+	+	+	(0.2)
Abandoned Underground Coal Mines	NC	NC	+	(0.1)	(0.1)	+
Mobile Combustion	+	+	+	+	+	+
Composting	NC	NC	NC	NC	NC	+
Petrochemical Production	NC	NC	NC	NC	NC	NC
Iron and Steel Production & Metallurgical Coke Production	NC	NC	NC	NC	NC	NC
Field Burning of Agricultural Residues	(0.5)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Incineration of Waste	NC	NC	NC	NC	+	+
International Bunker Fuels[a]	+	+	+	+	+	+
N_2O	**(7.1)**	**(4.5)**	**(5.4)**	**(3.1)**	**(2.6)**	**(7.4)**
Agricultural Soil Management	(5.7)	(3.3)	(4.5)	(2.3)	(1.6)	(5.1)
Mobile Combustion	+	+	+	+	+	+
Manure Management	0.1	0.4	0.6	0.7	0.8	0.8
Nitric Acid Production	(1.2)	(1.3)	(1.1)	(1.1)	(1.3)	(2.6)
Stationary Combustion	+	+	+	(0.1)	(0.1)	+
Forest Land Remaining Forest Land	+	+	+	+	+	+
Wastewater Treatment	+	+	+	+	+	+
N2O from Product Uses	NC	NC	NC	NC	NC	NC
Adipic Acid Production	+	+	NC	NC	NC	NC
Composting	NC	NC	NC	NC	NC	+
Settlements Remaining Settlements	NC	NC	NC	NC	+	(0.1)
Incineration of Waste	NC	NC	NC	NC	+	+

Field Burning of Agricultural Residues	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	+
International Bunker Fuels[a]	+	+	+	+	+	+
HFCs	**NC**	**+**	**1.0**	**1.6**	**2.1**	**2.5**
Substitution of Ozone Depleting Substances	NC	+	1.0	1.6	2.1	2.5
HCFC-22 Production	NC	NC	NC	NC	NC	NC
Semiconductor Manufacture	NC	NC	NC	NC	+	+
PFCs	**NC**	**NC**	**NC**	**NC**	**+**	**+**
Semiconductor Manufacture	NC	NC	NC	NC	+	+
Aluminum Production	NC	NC	NC	NC	NC	NC
SF_6	**1.8**	**1.0**	**1.2**	**0.9**	**0.5**	**+**
Electrical Transmission and Distribution	1.8	1.0	1.2	0.9	0.5	0.3
Magnesium Production and Processing	NC	NC	+	+	+	(0.1)
Semiconductor Manufacture	NC	NC	NC	NC	+	(0.2)
Net Change in Total Emissions[b]	**55.0**	**68.2**	**80.3**	**107.1**	**95.3**	**104.4**
Percent Change	**0.9%**	**1.0%**	**1.1%**	**1.5%**	**1.3%**	**1.5%**

+ Absolute value does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

Parentheses indicate negative values

NC (No Change)

[a] Not included in emissions total.

[b] Excludes net CO_2 flux from Land Use, Land-Use Change, and Forestry, and emissions from International Bunker Fuels.

Note: Totals may not sum due to independent rounding.

Table 10-2: Revisions to Net Flux of CO_2 to the Atmosphere from Land Use, Land-Use Change, and Forestry (Tg CO_2 Eq.)

Component: Net CO_2 Flux From Land Use, Land-Use Change, and Forestry	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**
Forest Land Remaining Forest Land	48.8	89.4	(105.0)	(105.0)	(105.0)	(99.1)
Cropland Remaining Cropland	NC	NC	NC	NC	NC	NC
Land Converted to Cropland	NC	NC	NC	NC	NC	NC
Grassland Remaining Grassland	(0.1)	+	0.1	0.1	0.2	0.2
Land Converted to Grassland	+	+	0.2	0.3	0.3	0.4
Settlements Remaining Settlements	NC	NC	NC	NC	NC	NC
Other	(0.7)	(1.9)	(1.4)	(0.6)	(1.1)	(1.7)
Net Change in Total Flux	**47.9**	**87.7**	**(106.1)**	**(105.2)**	**(105.5)**	**(100.1)**
Percent Change	**5.3%**	**13.2%**	**(11.2%)**	**(11.0%)**	**(11.0%)**	**(10.6%)**

NC (No Change)

Note: Numbers in parentheses indicate a decrease in estimated net flux of CO_2 to the atmosphere, or an increase in net sequestration.

Note: Totals may not sum due to independent rounding.

+ Absolute value does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2010. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES- 1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that

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[1] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. For calendar year 2010, the first year in which data were reported, facilities in 29 categories provided in 40 CFR part 98 were required to report their 2010 emissions by the September 30, 2011 reporting deadline.[7] The GHGRP dataset and the data presented in this inventory report are complementary and, as indicated in the respective planned improvements sections in this report's chapters, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this inventory.

[END BOX]

ES.1. Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[8] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2010, concentrations of these greenhouse gases have increased globally by 39, 158, and 19 percent, respectively (IPCC 2007 and NOAA/ESLR 2009).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and

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[7] See <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> and <http://ghgdata.epa.gov/ghgp/main.do>.

[8] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[9] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[10,11] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[12] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2010 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)
* The CH_4 GWP includes the direct effects and those indirect effects due

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[9] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[10] Carbon comprises 12/44^{ths} of carbon dioxide by weight.

[11] One teragram is equal to 10^{12} grams or one million metric tons.

[12] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2010, total U.S. greenhouse gas emissions were 6,821.8 Tg or million metric tons CO_2 Eq. Total U.S. emissions have increased by 10.5 percent from 1990 to 2010, and emissions increased from 2009 to 2010 by 3.2 percent (213.5 Tg CO_2 Eq.). The increase from 2009 to 2010 was primarily due to an increase in economic output resulting in an increase in energy consumption across all sectors, and much warmer summer conditions resulting in an increase in electricity demand for air conditioning that was generated primarily by combusting coal and natural gas. Since 1990, U.S. emissions have increased at an average annual rate of 0.5 percent.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2010.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.)

Gas/Source	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
CO_2	**5,100.5**	**6,107.6**	**6,019.0**	**6,118.6**	**5,924.3**	**5,500.5**	**5,706.4**
Fossil Fuel Combustion	4,738.3	5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
Electricity Generation	1,820.8	2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
Transportation	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Industrial	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Residential	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Commercial	219.0	223.5	208.6	218.9	225.1	224.6	224.2
U.S. Territories	27.9	50.0	50.3	46.1	39.8	41.7	41.6
Non-Energy Use of Fuels	119.6	144.1	143.8	134.9	138.6	123.7	125.1
Iron and Steel Production & Metallurgical Coke Production	99.6	66.0	68.9	71.1	66.1	42.1	54.3
Natural Gas Systems	37.6	29.9	30.8	31.0	32.8	32.2	32.3
Cement Production	33.3	45.2	45.8	44.5	40.5	29.0	30.5
Lime Production	11.5	14.4	15.1	14.6	14.3	11.2	13.2
Incineration of Waste	8.0	12.5	12.5	12.7	11.9	11.7	12.1
Limestone and Dolomite Use	5.1	6.8	8.0	7.7	6.3	7.6	10.0
Ammonia Production	13.0	9.2	8.8	9.1	7.9	7.9	8.7
Cropland Remaining Cropland	7.1	7.9	7.9	8.2	8.6	7.2	8.0
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	3.5	4.9	4.1	3.4	4.4
Soda Ash Production and Consumption	4.1	4.2	4.2	4.1	4.1	3.6	3.7
Petrochemical Production	3.3	4.2	3.8	3.9	3.4	2.7	3.3

Aluminum Production	6.8	4.1	3.8	4.3	4.5	3.0	3.0
Carbon Dioxide Consumption	1.4	1.3	1.7	1.9	1.8	1.8	2.2
Titanium Dioxide Production	1.2	1.8	1.8	1.9	1.8	1.6	1.9
Ferroalloy Production	2.2	1.4	1.5	1.6	1.6	1.5	1.7
Zinc Production	0.6	1.0	1.0	1.0	1.2	0.9	1.2
Phosphoric Acid Production	1.5	1.4	1.2	1.2	1.2	1.0	1.0
Wetlands Remaining Wetlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
Lead Production	0.5	0.6	0.6	0.6	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.1	0.2
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(881.8)*	*(1,085.9)*	*(1,110.4)*	*(1,108.2)*	*(1,087.5)*	*(1,062.6)*	*(1,074.7)*
Wood Biomass and Ethanol Consumption[b]	*218.6*	*228.6*	*233.7*	*241.1*	*252.1*	*244.1*	*266.1*
International Bunker Fuels[c]	*111.8*	*109.8*	*128.4*	*127.6*	*133.7*	*122.3*	*127.8*
CH_4	**668.3**	**625.8**	**664.6**	**656.2**	**667.9**	**672.2**	**666.5**
Natural Gas Systems	189.6	190.5	217.7	205.3	212.7	220.9	215.4
Enteric Fermentation	133.8	139.0	141.4	143.8	143.4	142.6	141.3
Landfills	147.7	112.7	111.7	111.7	113.1	111.2	107.8
Coal Mining	84.1	56.8	58.1	57.8	66.9	70.1	72.6
Manure Management	31.7	47.9	48.4	52.7	51.8	50.7	52.0
Petroleum Systems	35.2	29.2	29.2	29.8	30.0	30.7	31.0
Wastewater Treatment	15.9	16.5	16.7	16.6	16.6	16.5	16.3
Rice Cultivation	7.1	6.8	5.9	6.2	7.2	7.3	8.6
Stationary Combustion	7.5	6.6	6.2	6.5	6.6	6.3	6.3
Abandoned Underground Coal Mines	6.0	5.5	5.5	5.3	5.3	5.1	5.0
Forest Land Remaining Forest Land	2.5	8.1	17.9	14.6	8.8	5.8	4.8
Mobile Combustion	4.7	2.5	2.4	2.2	2.1	2.0	1.9
Composting	0.3	1.6	1.6	1.7	1.7	1.6	1.6
Petrochemical Production	0.9	1.1	1.0	1.0	0.9	0.8	0.9
Iron and Steel Production & Metallurgical Coke Production	1.0	0.7	0.7	0.7	0.6	0.4	0.5
Field Burning of Agricultural Residues	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuesl[c]	0.2	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*
N_2O	**316.2**	**331.9**	**336.8**	**334.9**	**317.1**	**304.0**	**306.2**
Agricultural Soil Management	200.0	213.1	211.1	211.1	212.9	207.3	207.8
Stationary Combustion	12.3	20.6	20.8	21.2	21.1	20.7	22.6
Mobile Combustion	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Manure Management	14.8	17.6	18.4	18.5	18.3	18.2	18.3
Nitric Acid Production	17.6	16.4	16.1	19.2	16.4	14.5	16.7
Wastewater Treatment	3.5	4.7	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Forest Land Remaining Forest Land	2.1	7.0	15.0	12.2	7.5	5.1	4.3
Adipic Acid Production	15.8	7.4	8.9	10.7	2.6	2.8	2.8
Composting	0.4	1.7	1.8	1.8	1.9	1.8	1.7
Settlements Remaining Settlements	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*1.2*
HFCs	**36.9**	**115.0**	**116.0**	**120.0**	**117.5**	**112.1**	**123.0**
Substitution of Ozone Depleting	0.3	99.0	101.9	102.7	103.6	106.3	114.6

Substances							
HCFC-22 Production	36.4	15.8	13.8	17.0	13.6	5.4	8.1
Semiconductor Manufacture	0.2	0.2	0.3	0.3	0.3	0.3	0.3
PFCs	**20.6**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**	**5.6**
Semiconductor Manufacture	2.2	3.2	3.5	3.7	4.0	4.0	4.1
Aluminum Production	18.4	3.0	2.5	3.8	2.7	1.6	1.6
SF_6	**32.6**	**17.8**	**16.8**	**15.6**	**15.0**	**13.9**	**14.0**
Electrical Transmission and Distribution	26.7	13.9	13.0	12.2	12.2	11.8	11.8
Magnesium Production and Processing	5.4	2.9	2.9	2.6	1.9	1.1	1.3
Semiconductor Manufacture	0.5	1.0	1.0	0.8	0.9	1.0	0.9
Total	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Net Emission (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2010. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.6 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have decreased by 0.3 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management, mobile source fuel combustion and stationary fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted from semiconductor manufacturing and as a by-product of primary aluminum production, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percentages based on Tg CO_2 Eq.)

Overall, from 1990 to 2010, total emissions of CO_2 increased by 605.9 Tg CO_2 Eq. (11.9 percent), while total emissions of CH_4 and N_2O decreased by 1.7 Tg CO_2 Eq. (0.3 percent), and 10.0 Tg CO_2 Eq. (3.2 percent), respectively. During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 52.5 Tg CO_2 Eq. (58.2 percent). From 1990 to 2010, HFCs increased by 86.1 Tg CO_2 Eq. (233.1 percent), PFCs decreased by 15.0 Tg CO_2 Eq. (72.7 percent), and SF_6 decreased by 18.6 Tg CO_2 Eq. (57.0 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.8 percent of total emissions in 2010. The following sections describe each gas's contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 39 percent (IPCC 2007 and NOAA/ESLR 2009), principally due to the combustion of fossil fuels. Within the

United States, fossil fuel combustion accounted for 94.4 percent of CO_2 emissions in 2010. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[13] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2010 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.7 percent from 1990 to 2010. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 21 years, and (2) an overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2010, CO_2 emissions from fossil fuel combustion increased from 4,738.3 Tg CO_2 Eq. to 5,387.8 Tg CO_2 Eq.—a 13.7 percent total increase over the twenty-one-year period. From 2009 to 2010, these emissions increased by 181.6 Tg CO_2 Eq. (3.5 percent).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or “end-use” sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector’s share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

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[13] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990	2005	2006	2007	2008	2009	2010
Transportation	**1,489.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.5**	**1,732.4**	**1,750.0**
Combustion	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Electricity	3.0	4.7	4.5	5.1	4.7	4.5	4.5
Industrial	**1,533.1**	**1,553.3**	**1,560.2**	**1,559.8**	**1,503.8**	**1,328.6**	**1,415.4**
Combustion	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Electricity	686.8	737.0	712.0	715.4	697.3	602.0	637.6
Residential	**931.4**	**1,214.7**	**1,152.4**	**1,205.2**	**1,192.2**	**1,125.5**	**1,183.7**
Combustion	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Electricity	593.0	856.7	830.8	863.5	842.9	786.5	843.5
Commercial	**757.0**	**1,027.2**	**1,007.6**	**1,047.7**	**1,041.1**	**978.0**	**997.1**
Combustion	219.0	223.5	208.6	218.9	225.1	224.6	224.2
Electricity	538.0	803.7	799.0	828.8	816.0	753.5	772.9
U.S. Territories[a]	**27.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**	**41.6**
Total	**4,738.3**	**5,746.5**	**5,653.0**	**5,757.8**	**5,571.5**	**5,206.2**	**5,387.8**
Electricity Generation	**1,820.8**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,146.4**	**2,258.4**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 32 percent of CO_2 emissions from fossil fuel combustion in 2010.[14] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2010, transportation emissions rose by 18 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 34 percent from 1990 to 2010, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2010. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2010. Both sectors relied heavily on electricity for meeting energy demands, with 71 and 78 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 29 percent since 1990, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

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[14] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 34.0 percent of U.S. emissions from fossil fuel combustion in 2010.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 42 percent of the CO_2 from fossil fuel combustion in 2010. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 94 percent of all coal consumed for energy in the United States in 2010. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 5.5 Tg CO_2 Eq. (4.6 percent) from 1990 through 2010. Emissions from non-energy uses of fossil fuels were 125.1 Tg CO_2 Eq. in 2010, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production increased by 12.2 Tg CO_2 Eq. (28.9 percent) from 2009 to 2010, upsetting a trend of decreasing emissions. Despite this, from 1990 through 2010 emissions declined by 45.5 percent (45.3 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2010, CO_2 emissions from cement production increased by 1.5 Tg CO_2 Eq. (5.1 percent) from 2009. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the three years prior to 2010. Overall, from 1990 to 2010, emissions from cement production have decreased by 8.3 percent, a decrease of 2.8 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 192.8 Tg CO_2 Eq. (21.9 percent) from 1990 through 2010. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 158 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2010 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2010 with 215.4 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 25.8 Tg CO_2 Eq. (13.6 percent) since 1990.
- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2010, enteric fermentation CH_4 emissions were 141.3 Tg CO_2 Eq. (21.2 percent of total CH_4 emissions), which represents an increase of 7.5 Tg CO_2 Eq. (5.6 percent) since 1990.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 16.2 percent of total CH_4 emissions (107.8 Tg CO_2 Eq.) in 2010. From 1990 to 2010, CH_4 emissions from landfills decreased by 39.8 Tg CO_2 Eq. (27.0 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas

collected and combusted,[15] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- In 2010, CH_4 emissions from coal mining were 72.6 Tg CO_2 Eq., a 2.5 Tg CO_2 Eq. (3.5 percent) increase over 2009 emission levels. The overall decline of 11.5 Tg CO_2 Eq. (13.6 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Methane emissions from manure management increased by 64.0 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 52.0 Tg CO_2 Eq. in 2010. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 19 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, stationary fuel combustion, manure management and nitric acid production (see Figure ES-9).

Figure ES-9: 2010 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2010, N_2O emissions from mobile combustion were 20.6 Tg CO_2 Eq. (approximately 6.7 percent of U.S. N_2O emissions). From 1990 to 2010, N_2O emissions from mobile combustion decreased by 53.1 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 2.8 Tg CO_2 Eq. in 2010, and have decreased significantly in recent years due to the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 82.2 percent since 1990 and by 84.0 percent since a peak in 1995.
- N_2O emissions from stationary combustion increased 10.3 Tg CO_2 Eq. (84.4 percent) from 1990 through 2010. N_2O emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- Agricultural soils accounted for approximately 67.9 percent of N_2O emissions in the United States in 2010. Estimated emissions from this source in 2010 were 207.8 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2010, although overall emissions were 3.9 percent higher in 2010 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the

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[15] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ozone depleting substances (ODS) (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 114.6 Tg CO_2 Eq. in 2010. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-out of ODS required under the Montreal Protocol came into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 77.8 percent (28.3 Tg CO_2 Eq.) from 1990 through 2010, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 55.7 percent (14.9 Tg CO_2 Eq.) from 1990 to 2010, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (16.9 Tg CO_2 Eq.) from 1990 to 2010, due to both industry emission reduction efforts and declines in domestic aluminum production.

ES.3. Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-one-year period of 1990 to 2010, total emissions in the Energy and Agriculture sectors grew by 645.8 Tg CO_2 Eq. (12.2 percent), and 40.6 Tg CO_2 Eq. (10.5 percent), respectively. Emissions slightly decreased in the Industrial Processes sector by 10.5 Tg CO_2 Eq. (3.4 percent) , while emissions from the Waste and Solvent and Other Product Use sectors decreased by 35.2 Tg CO_2 Eq. (21.0 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 187.0 Tg CO_2 Eq. (21.5 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	1990	2005	2006	2007	2008	2009	2010
Energy	5,287.7	6,282.4	6,214.4	6,294.3	6,125.4	5,752.7	5,933.5
Industrial Processes	313.9	330.1	335.5	347.3	319.1	268.2	303.4

Solvent and Other Product Use	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Agriculture	387.8	424.6	425.4	432.6	433.8	426.4	428.4
Land-Use Change and Forestry	13.8	25.6	43.2	37.6	27.4	20.6	19.6
Waste	167.7	137.2	136.5	136.7	138.2	136.0	132.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land-Use Change and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Emissions and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2010. In 2010, approximately 85 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 15 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (50 percent and 14 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87.0 percent of total U.S. greenhouse gas emissions in 2010.

Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4.4 percent of U.S. greenhouse gas emissions in 2010.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2010.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 21.2 percent and 7.8 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2010. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2010, accounting for 67.9 percent. In 2010, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 86 percent of total 2010 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2010. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2010 resulted in a net C sequestration of 1,074.7 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18.8 percent of total U.S. CO_2 emissions, or 15.8 percent of total greenhouse gas emissions in 2010. Between 1990 and 2010, total land use, land-use change, and forestry net C flux resulted in a 21.9 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Forest Land Remaining Forest Land	(701.4)	(940.9)	(963.5)	(959.2)	(938.3)	(910.6)	(921.8)
Cropland Remaining Cropland	(29.4)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)	(15.6)
Land Converted to Cropland	2.2	5.9	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)	(8.3)
Land Converted to Grassland	(19.8)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)	(23.6)
Settlements Remaining Settlements	(57.1)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	(98.0)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(11.6)	(11.0)	(10.9)	(10.9)	(12.7)	(13.3)
Total	**(881.8)**	**(1,085.9)**	**(1,110.4)**	**(1,108.2)**	**(1,087.5)**	**(1,062.6)**	**(1,074.7)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. Liming of agricultural soils and urea fertilization in 2010 resulted in CO_2 emissions of 3.9 Tg CO_2 Eq. (3,906 Gg) and 4.1 Tg CO_2 Eq. (4,143 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.0 Tg CO_2 Eq. (983 Gg), and N_2O emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2010 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2010 accounted for 1.4 Tg CO_2 Eq. (5 Gg). This represents an increase of 43 percent since 1990. Forest fires in 2010 resulted in CH_4 emissions of 4.8 Tg CO_2 Eq. (231 Gg), and in N_2O emissions of 4.0 Tg CO_2 Eq. (14 Gg).

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2005	2006	2007	2008	2009	2010
CO_2	**8.1**	**8.9**	**8.8**	**9.2**	**9.6**	**8.3**	**9.0**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.2	4.5	5.0	3.7	3.9
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.7	3.8	3.6	3.6	4.1
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
CH_4	**2.5**	**8.1**	**17.9**	**14.6**	**8.8**	**5.8**	**4.8**
Forest Land Remaining Forest Land: Forest Fires	2.5	8.1	17.9	14.6	8.8	5.8	4.8
N_2O	**3.1**	**8.5**	**16.5**	**13.8**	**9.0**	**6.5**	**5.7**
Forest Land Remaining Forest Land: Forest Fires	2.1	6.6	14.6	11.9	7.2	4.7	4.0
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**13.8**	**25.6**	**43.2**	**37.6**	**27.4**	**20.6**	**19.6**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 81.4 percent of this chapter's emissions, and 16.2 percent of total U.S. CH_4 emissions.[16] Additionally, wastewater treatment accounts for 16.1 percent of Waste emissions, 2.5 percent of U.S. CH_4 emissions, and 1.6 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.6 Tg CO_2 Eq. and 1.7 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 1.9 percent of total U.S. greenhouse gas emissions in 2010.

ES.4. Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2010.

Figure ES-13: Emissions Allocated to Economic Sectors

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[16] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Electric Power Industry	1,866.2	2,448.8	2,393.0	2,459.1	2,405.8	2,191.4	2,306.5
Transportation	1,545.2	2,017.5	1,994.5	2,002.4	1,889.8	1,819.3	1,834.0
Industry	1,564.8	1,438.1	1,499.8	1,489.6	1,448.5	1,317.2	1,394.2
Agriculture	431.9	496.0	516.7	517.6	505.8	492.8	494.8
Commercial	388.0	374.3	359.9	372.2	381.8	382.0	381.7
Residential	345.4	371.3	336.1	358.4	368.4	360.0	365.2
U.S. Territories	33.7	58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (34 percent) of U.S. greenhouse gas emissions in 2010. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2010. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 19 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial and residential sectors accounted for 6 and 5 percent, respectively, of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[17] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of U.S. greenhouse gas emissions (30 percent) in 2010. Transportation is the second largest contributor to total U.S. emissions (27 percent). The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2010. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2010.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed

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[17] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

(Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Industry	2,237.7	2,159.9	2,198.5	2,185.9	2,131.5	1,905.8	2,019.0
Transportation	1,548.3	2,022.3	1,999.1	2,007.6	1,894.6	1,823.9	1,838.6
Residential	953.2	1,244.6	1,183.4	1,238.5	1,227.3	1,162.9	1,226.6
Commercial	939.4	1,193.6	1,174.8	1,216.9	1,213.3	1,151.3	1,171.0
Agriculture	462.9	525.5	544.2	550.5	533.3	518.9	521.1
U.S. Territories	33.7	58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES- 2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2010; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.5 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Growth Rate**[a]
GDP[b]	100	157	161	165	164	158	163	2.5%
Electricity Consumption[c]	100	134	135	137	136	131	137	1.6%
Fossil Fuel Consumption[c]	100	119	117	119	116	109	113	0.6%
Energy Consumption[c]	100	119	118	121	119	113	117	0.8%
Population[d]	100	118	120	121	122	123	123	1.1%
Greenhouse Gas Emissions[e]	100	117	116	117	114	107	110	0.5%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[18] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[19] which are regulated under the Clean Air Act. Table ES-10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES-10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2005	2006	2007	2008	2009	2010
NO_x	**21,705**	**15,899**	**15,039**	**14,380**	**13,545**	**11,467**	**11,467**
Mobile Fossil Fuel Combustion	10,862	9,012	8,488	7,965	7,441	6,206	6,206
Stationary Fossil Fuel Combustion	10,023	5,858	5,545	5,432	5,148	4,159	4,159
Industrial Processes	591	569	553	537	520	568	568
Oil and Gas Activities	139	321	319	318	318	393	393
Incineration of Waste	82	129	121	114	106	128	128
Agricultural Burning	8	6	7	8	8	8	8
Solvent Use	1	3	4	4	4	3	3
Waste	+	2	2	2	2	2	2
CO	**129,976**	**70,791**	**67,227**	**63,613**	**59,993**	**51,431**	**51,431**
Mobile Fossil Fuel Combustion	119,360	62,692	58,972	55,253	51,533	43,355	43,355
Stationary Fossil Fuel Combustion	5,000	4,649	4,695	4,744	4,792	4,543	4,543
Industrial Processes	4,125	1,555	1,597	1,640	1,682	1,549	1,549
Incineration of Waste	978	1,403	1,412	1,421	1,430	1,403	1,403
Agricultural Burning	268	184	233	237	270	247	247
Oil and Gas Activities	302	318	319	320	322	345	345
Waste	1	7	7	7	7	7	7
Solvent Use	5	2	2	2	2	2	2
NMVOCs	**20,930**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**	**9,313**
Mobile Fossil Fuel Combustion	10,932	6,330	6,037	5,742	5,447	4,151	4,151
Solvent Use	5,216	3,851	3,846	3,839	3,834	2,583	2,583
Industrial Processes	2,422	1,997	1,933	1,869	1,804	1,322	1,322
Stationary Fossil Fuel Combustion	912	716	918	1,120	1,321	424	424
Oil and Gas Activities	554	510	510	509	509	599	599
Incineration of Waste	222	241	238	234	230	159	159
Waste	673	114	113	111	109	76	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**	**8,599**
Stationary Fossil Fuel Combustion	18,407	11,541	10,612	10,172	8,891	7,167	7,167
Industrial Processes	1,307	831	818	807	795	798	798
Mobile Fossil Fuel Combustion	793	889	750	611	472	455	455
Oil and Gas Activities	390	181	182	184	187	154	154

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[18] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[19] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Incineration of Waste	38	24	24	24	23	24	24
Waste	+	1	1	1	1	1	1
Solvent Use	+	+	+	+	+	+	+
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 Gg.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[20] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2010 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2010 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the

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[20] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[BEGIN BOX]

Box ES- 3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2010) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

[END BOX]

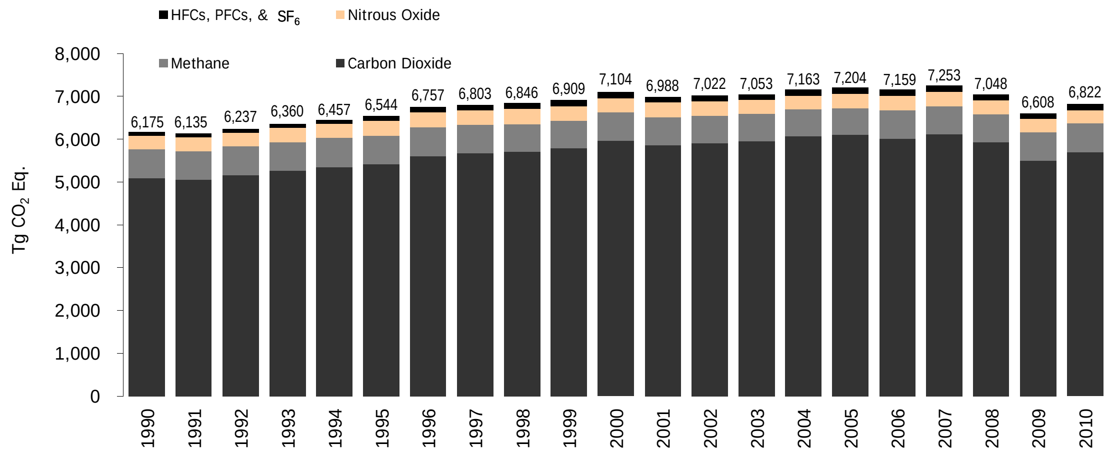


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

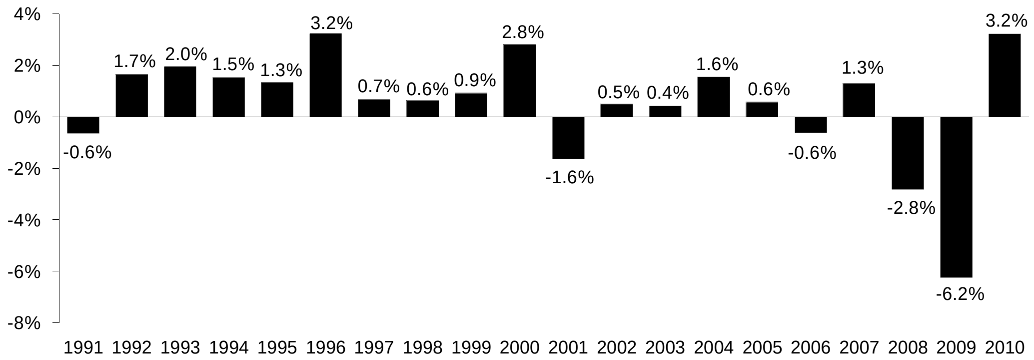


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

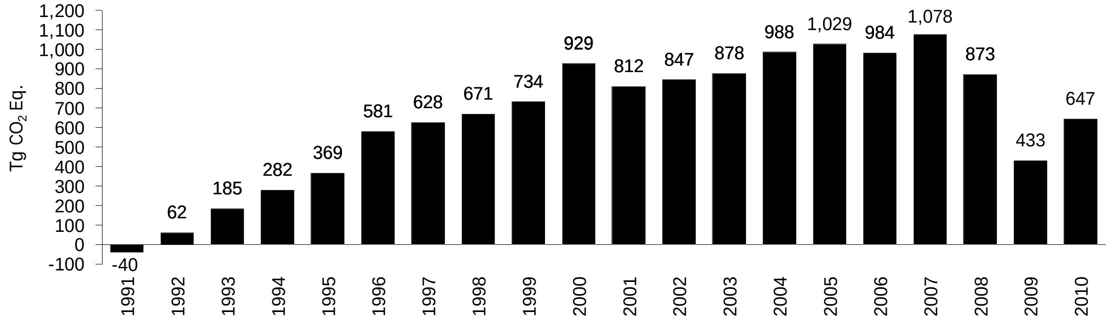


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

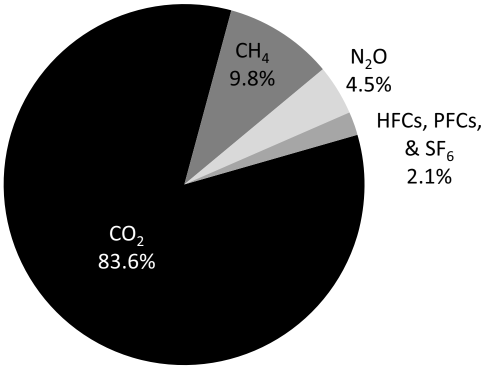


Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percents based on Tg CO$_2$ Eq.)

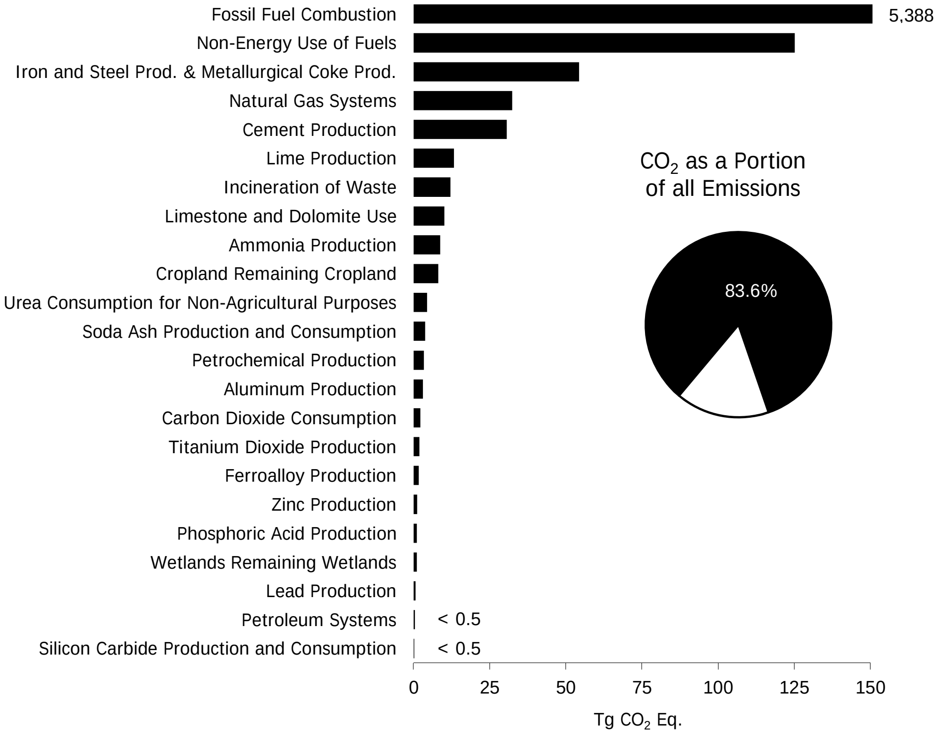


Figure ES-5: 2010 Sources of CO$_2$ Emissions

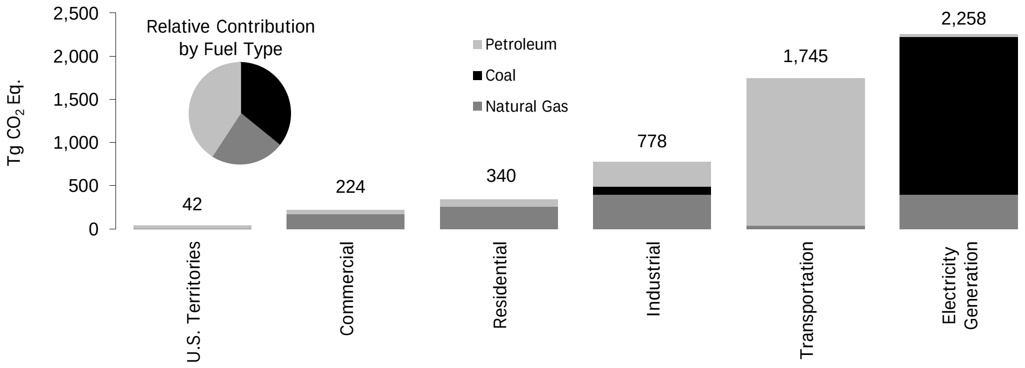


Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

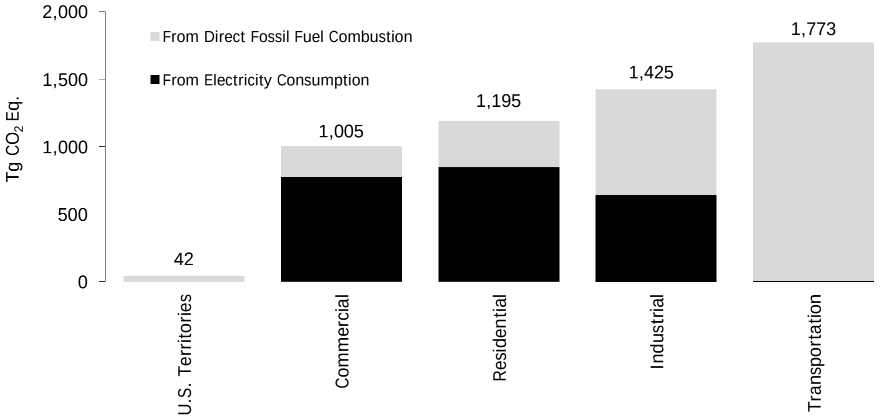


Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

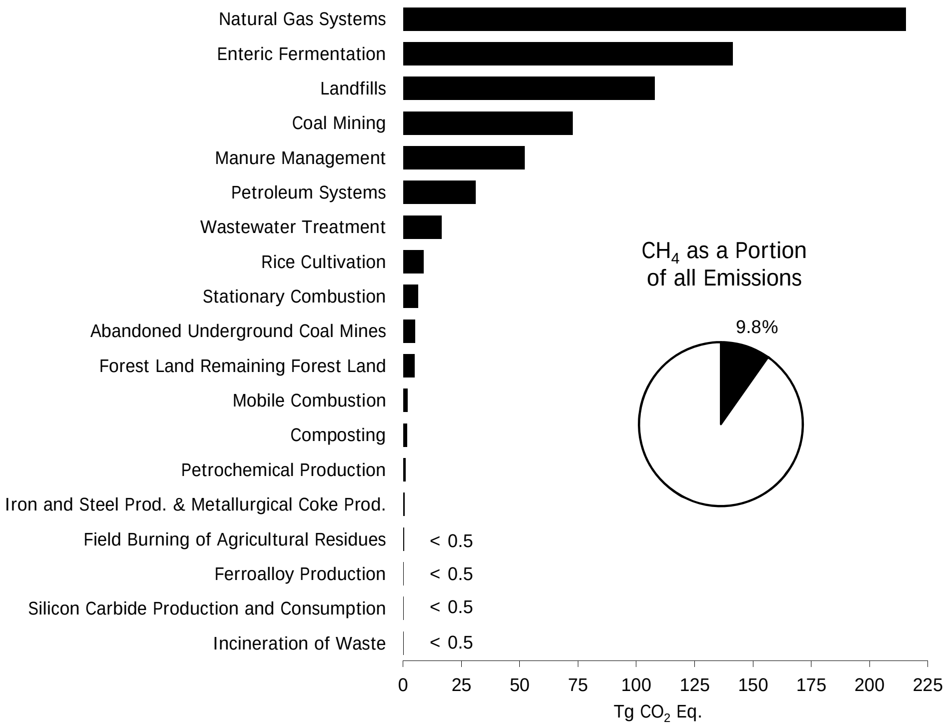


Figure ES-8: 2010 Sources of CH_4 Emissions

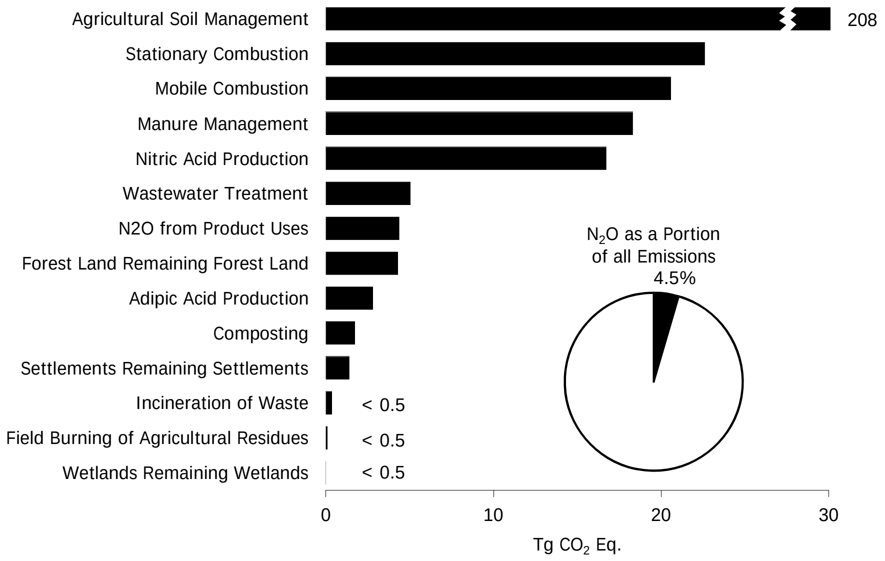


Figure ES-9: 2010 Sources of N_2O Emissions

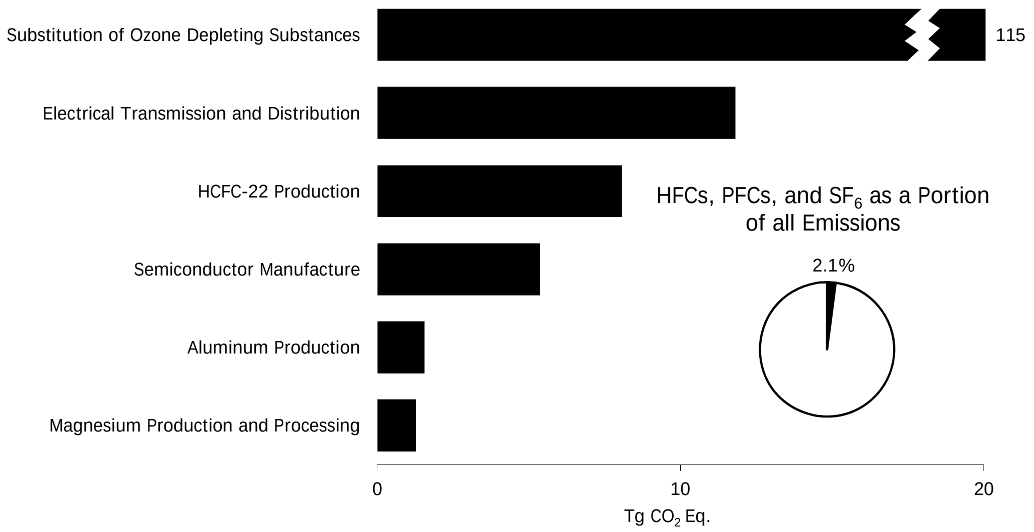
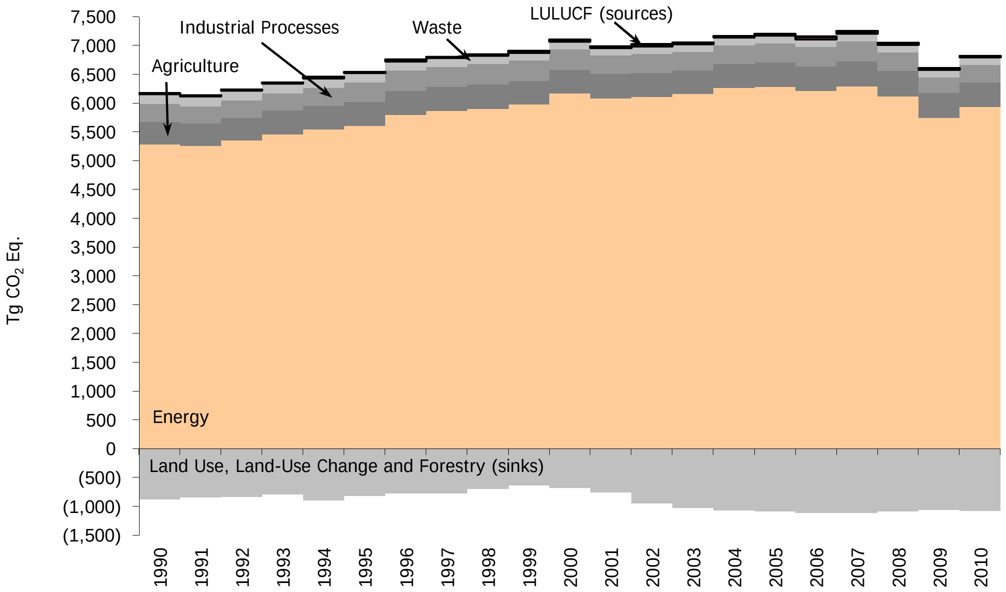


Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

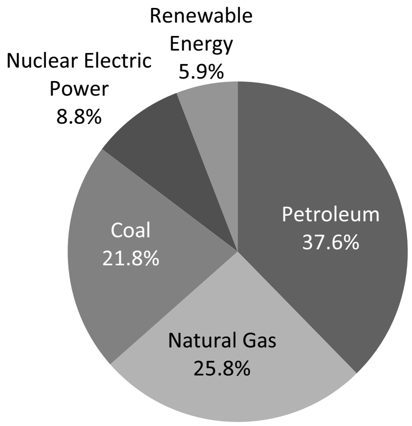


Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

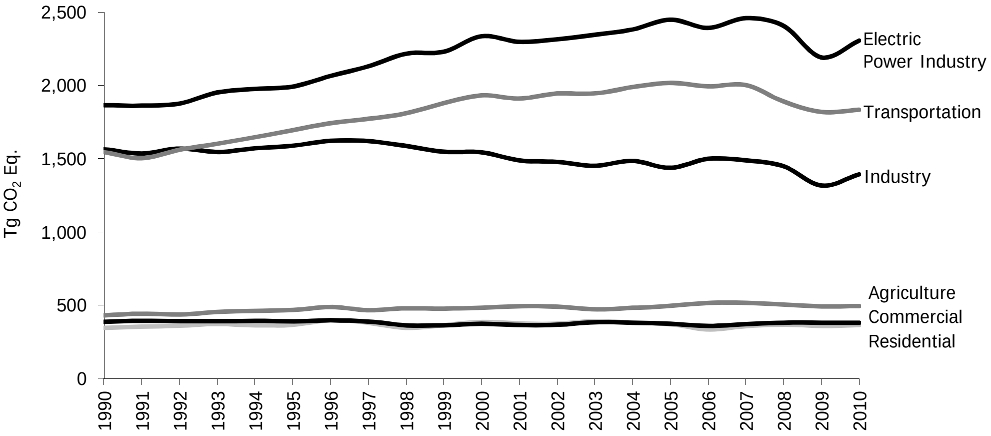


Figure ES-13: Emissions Allocated to Economic Sectors

Note: Does not include U.S. Territories.

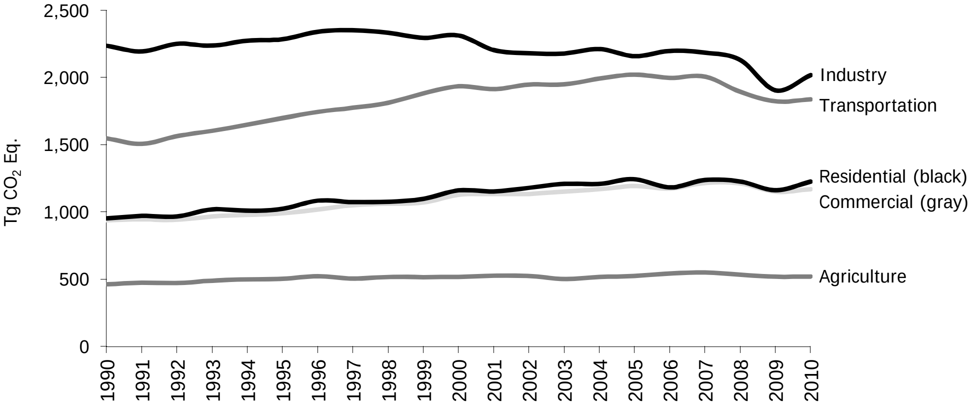


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

Note: Does not include U.S. Territories.

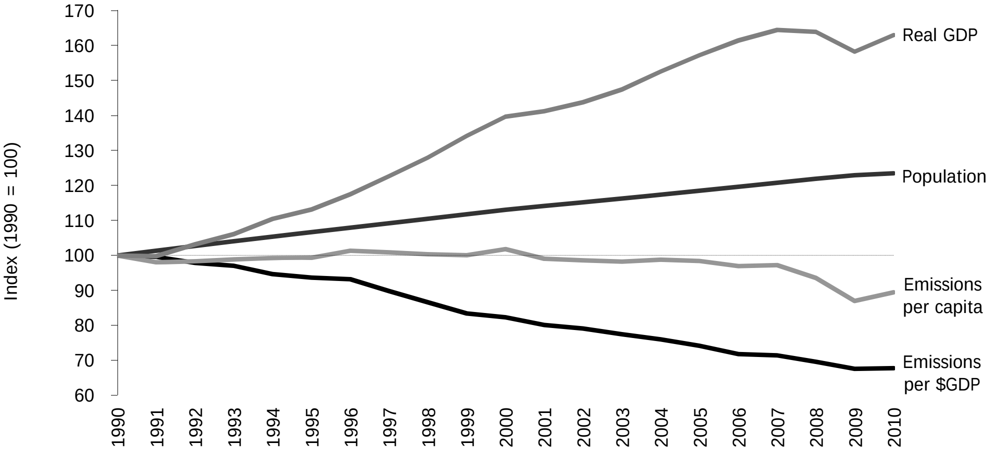


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

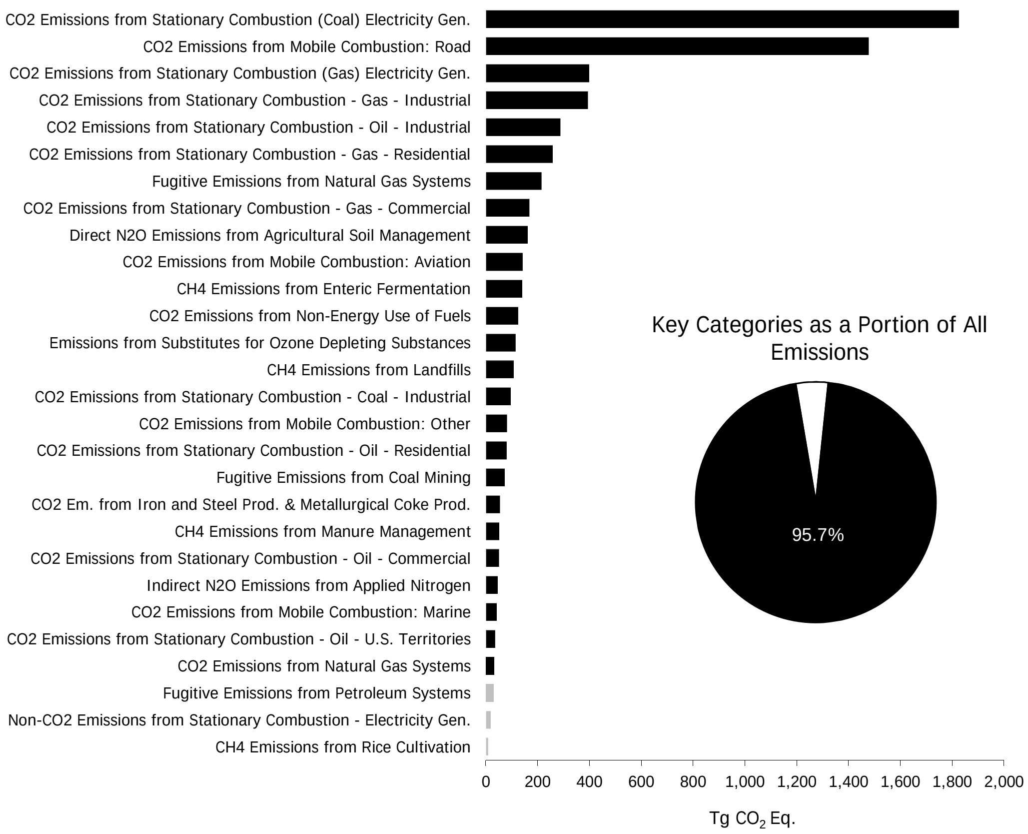


Figure ES-16: 2010 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal

August 25, 2011

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Executive Summary

— **Research conclusion and key messages—natural gas offers greenhouse gas advantages over coal:** Natural gas has been widely discussed as a less carbon-intensive alternative to coal as a power sector fuel. In April 2011, the U.S. Environmental Protection Agency released revised methodologies for estimating fugitive methane emissions from natural gas systems. These revisions mostly affected the production component of the natural gas value chain (namely, gas well cleanups), causing a very substantial increase in the methane emissions estimate from U.S. natural gas systems.[1,2] This large increase in the upstream component of the natural gas value chain caused some to question the GHG advantage of gas versus coal over the entire life-cycle from source to use. As a result of this renewed attention, while it remains unambiguous that natural gas has a lower carbon content per unit of energy than coal does, several recent bottom-up studies have questioned whether natural gas retains its greenhouse gas advantage when the entire life cycles of both fuels are considered.[3]

Particular scrutiny has focused on shale formations, which are the United States' fastest growing marginal supply source of natural gas. Several recent bottom-up life-cycle studies have found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas.[4] Consequently, if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply.

Applying the latest emission factors from the EPA's 2011 upward revisions, our top-down life-cycle analysis

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[1] *EPA, Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009, U.S. EPA, EPA 430-R-11-005, http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, cited in Mark Fulton, et al., "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal," 14 March 2011, available at http://www.dbcca.com/dbcca/EN/_media/Comparing_Life_Cycle_Greenhouse_Gas.pdf.*

[2] *Note: For example, the EPA's estimates of methane emissions from U.S. natural gas systems in the base year of 2008 increased 120 percent between the 2010 and 2011 versions of their Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

[3] *The two approaches for an LCA study are bottom-up and top-down. A bottom-up study analyzes the emissions from an individual representative or prototype process or facility and calculates the emissions of that specific part of the value chain. It then combines each step of the value chain to compute the total lifecycle emissions from source to use. A top-down study, in contrast, looks at the total national emissions for a particular use or sector and depicts the national average life-cycle emissions for each discrete part of source to use for that sector to arrive at an aggregate estimate. Each approach has benefits and limitations. The bottom-up approach provides insights into the emissions for a particular process or fuel source, but also depicts only that specific process or source. The top-down approach represents the emissions across an entire sector but does not focus on specific processes or technologies. Some of the data sources for a top-down analysis may be built up from bottom-up sources, but the top-down analysis still yields a more general result.*

[4] *Robert W. Howarth, et al., "Methane and the greenhouse-gas footprint of natural gas from shale formations,"* Climatic Change *(2011); Timothy J. Skone, National Energy Technology Laboratory (NETL), "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presentation (Ithaca, NY: 12 May 2011; revised 23 May 2011); Mohan Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus Shale gas,"* Environmental Research Letters *6 (3), 5 August 2011.*

(LCA)[5] finds that the EPA's new methodology increases the life-cycle emissions estimate of natural gas-fired electricity for the baseline year of 2008 by about 11 percent compared with its 2010 methodology. But even with these adjustments, we conclude that **on average, U.S. natural gas-fired electricity generation still emitted 47 percent less GHGs than coal from source to use using the IPCC's 100-year global warming potential for methane of 25**. This figure is consistent with the findings of all but one of the recent life-cycle analyses that we reviewed.

While our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention. In its recent report on improving the safety of hydraulic fracturing, the U.S. Secretary of Energy's Advisory Board's Subcommittee on Shale Gas Production recommended that immediate efforts be launched to gather improved methane emissions data from shale gas operations.[6] In the meantime, methane emissions during the production, processing, transport, storage, and distribution of all forms of natural gas can be mitigated immediately using a range of existing technologies and best practices, many of which have payback times of three years or less.[7] Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas. Although the adoption of these practices has been largely voluntary to date, the EPA proposed new air quality rules in July 2011 that would require the industry to mitigate many of the methane emissions associated with natural gas development, and in particular with shale gas development.[8]

[illegible] This paper seeks to assess the current state of knowledge about the average greenhouse gas footprints of average coal and natural gas-fired electricity in the system today, how the growing share of natural gas production from shale formations could change this greenhouse gas footprint at the margin, and what the findings imply for policymakers, investors and the environment. In the first part of the paper, we examine recent bottom-up life-cycle analyses to provide context for our top-down analysis. These bottom-up analyses' estimation of the life-cycle GHG footprint of shale gas provides information about the potential marginal GHG impact of shale's rising share in the U.S. natural gas supply, as well as which emissions streams can be targeted for the greatest GHG mitigation. In the second part of the paper, we conduct our own top-down life-cycle analysis of GHGs from natural-gas and coal-fired electricity in 2008 using the EPA's revised 2011 estimates as well as other publically available government data. We make three key adjustments to the data sets in order to calculate a more accurate and meaningful national level inventory. we include: 1) emissions associated with net natural gas and coal imports; 2) natural gas produced as a byproduct of petroleum production, and 3) the share of natural gas that passes through distribution pipelines before reaching power plants. This top-down analysis examines the implications of the EPA's revised (2011) estimates for the current and future average greenhouse gas footprint of U.S. natural gas-fired electricity and its comparison with coal-fired electricity.

[illegible] Global warming potentials (GWPs) are used to convert the volumes of greenhouse gases with different heat-trapping properties into units of carbon dioxide-equivalent (CO_2e) for the purpose of examining the relative climate forcing impacts of different volumes of gas over discrete time periods. The Intergovernmental Panel on Climate Change's (IPCC) most recent assessment, published in 2007, estimates methane's GWP to be 25 times greater than that of carbon dioxide over a 100-year timeframe and 72 times greater than that of carbon dioxide over a 20-year timeframe.[9] Unless

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[5] "Life-cycle analysis" (LCA) is a generic term, and the methodology and scope of analysis can vary significantly across studies. Our analysis assesses GHGs during the production, processing, transport, and use of natural gas and coal to generate electricity. Some studies include not only the direct and indirect emissions from the plant or factory that provides or makes a certain product, but also the emissions associated with the inputs used to manufacture and create the production facilities themselves. This study does not address the manufacturing, construction, or decommissioning of the equipment used in energy production. As with any study, the certainty of conclusions drawn from an LCA can only be as strong as the underlying data.

[6] U.S. Department of Energy, Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, 90-Day Report, 18 August 2011, [illegible]

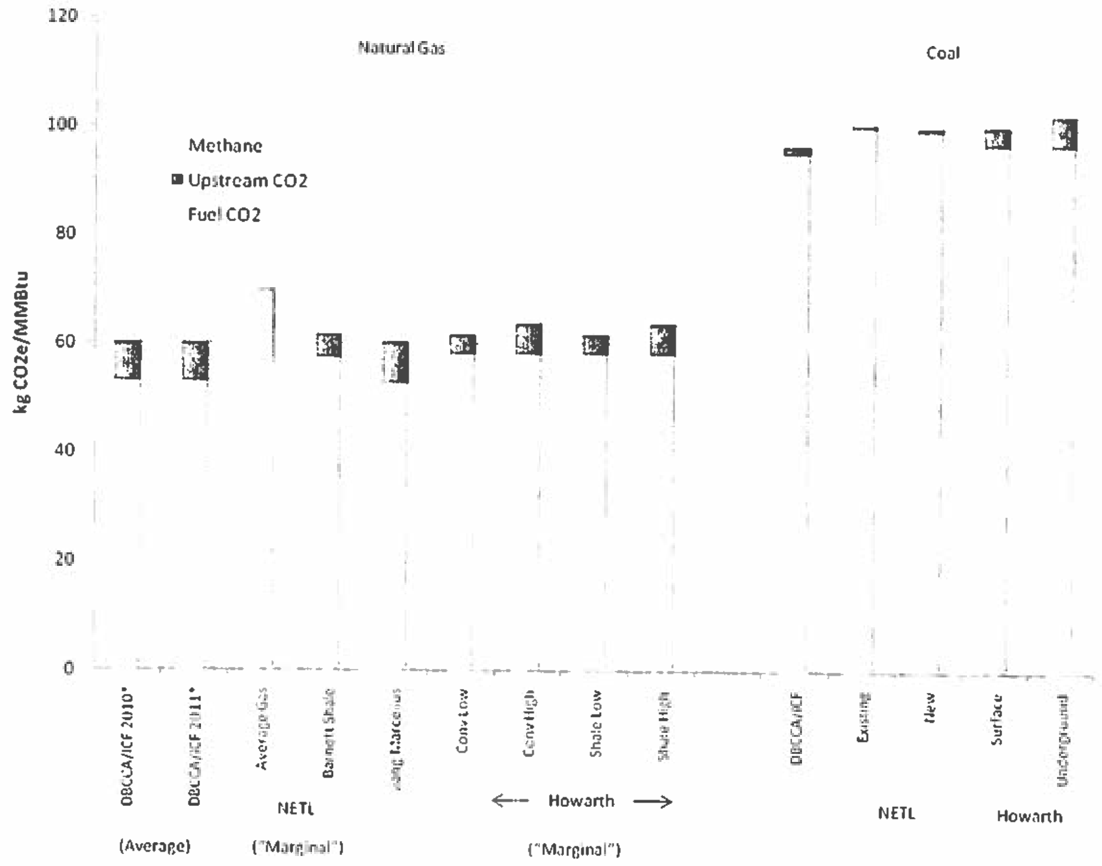
[7] Numerous technologies and best practices to capture methane that would otherwise be vented during natural gas production, processing, transport, or distribution have been detailed by the U.S. EPA's voluntary Natural Gas STAR Program. Many of these have payback periods under 3 years. U.S. Environmental Protection Agency, Natural Gas STAR Program, "Recommended Technologies and Practices," available at [illegible], viewed 29 July 2011.

[8] EPA, "Oil and Natural Gas Air Pollution Standards," [illegible], viewed 18 August 2011.

[9] Piers Forster et al., 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D.

otherwise specified, our analysis uses the 100-year GWP of 25 but we also calculate life-cycle emissions using a range of methane GWPs that have been proposed—including 72 and 105—in Appendix B of this report in order to show the sensitivities of the outputs to GWP. The choice of GWP does impact the relative GHG footprint between coal and gas. However, the life-cycle GHG footprint of gas is lower than coal under all GWPs tested, with the smallest difference calculated using a GWP of 105, where the GHG emissions in kilograms CO_2 per megawatt-hour of electricity generated (kg CO_2e/MWh) are 27 percent less than those of coal-fired generation.

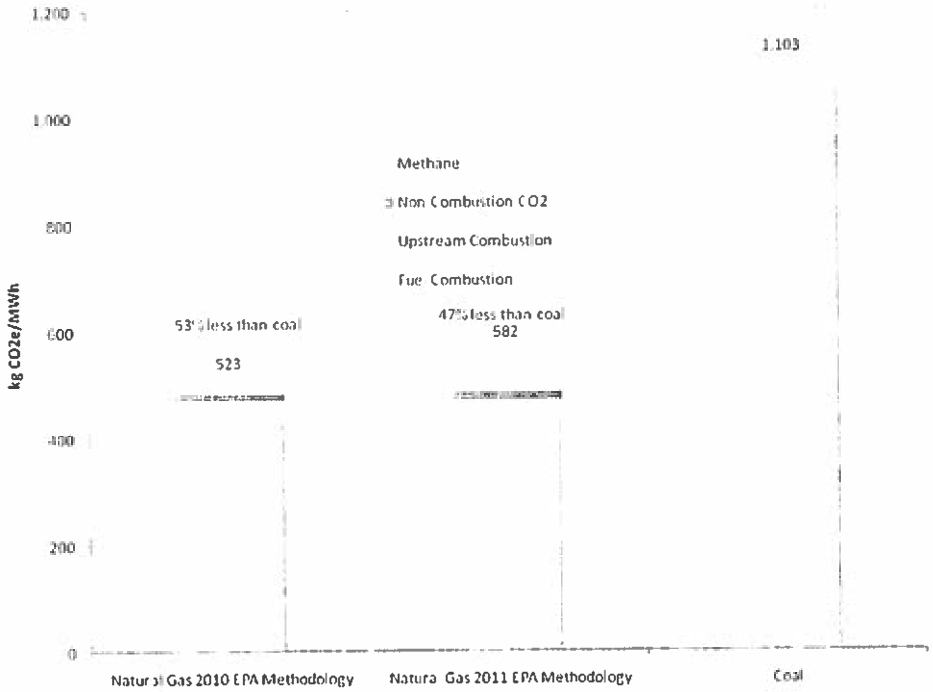
In addition, assumed power plant efficiencies also have a measurable impact on the life-cycle comparison between natural gas and coal-fired electricity generation. Unless otherwise specified, our analysis uses average U.S. heat rates for coal and natural gas plants for the existing capital stock: 11,044 Btu/kWh (31% efficiency) for coal and 8,044 Btu/kWh (41% efficiency) for natural gas plants. We also calculate life-cycle emissions using heat rate estimates for new U.S. natural gas and coal plants in Appendix A (Exhibit A-11).



Source: DBCCA Analysis 2011; NETL 2011; Jiang 2011; Howarth 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. See page 10 for more information. *2011 EPA methodology compared to 2010.

Qin, M Manning, Z Chen, M Marquis, K B Averyt, M Tignor and H L Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, p. 212

ES-1: [illegible] U.S. Life-Cycle GHG Emissions from Coal and Gas Electricity Generation 2008 [illegible] EPA 2010 Methodology [illegible] EPA 2011 Methodology



Source: DBCCA Analysis 2011. See pages 19 and 20 for more details.

Introduction and Key Exhibits

Our methodology Our top-down analysis addresses the emissions of three GHGs emitted during the production, processing, storage, transmission, distribution, and use of natural gas and coal in power plants

1. Carbon dioxide (CO_2);
2. Methane (CH_4) and;
3. Nitrous oxide (N_2O)

Carbon dioxide is a product of fossil fuel combustion and is also released during some stages of gas processing. Methane, the primary component of natural gas (roughly 98 percent of pipeline-quality gas), is a potent GHG.[10] It is released at many points during the life-cycle of natural gas production and use and also during coal mining, and it is an important component of the life-cycle emissions of both fuels, but especially of natural gas. Methane emissions can be categorized as "fugitive" or "vented" emissions. Fugitive emissions include unintentional "leaks" from poorly sealed valves, flanges, meters, and other equipment.[11] Venting is the intentional release of methane as part of the operating procedure for a particular process. For example, when a compressor or a pipeline is taken out of service for repair, the compressed gas in the equipment may be released. There are a variety of venting operations associated with natural gas production that account for the majority of methane emissions in the natural gas sector. Because the amount of fugitive and vented methane is highly dependent on the practices and technologies that are used, the amount of methane emitted can vary significantly by facility and/or the stripping and "clean up" process employed. Although small amounts of methane and nitrous oxide are also emitted during fossil fuel combustion, carbon dioxide is by far the largest greenhouse gas product. In this paper, because the amounts of methane and nitrous oxide are such a small fraction of the total combustion-related emissions, we include them together with CO_2 on tables and figures under the heading "combustion."[12]

Roadmap summary In the section that follows, we start with a review of recent LCA studies. These studies have attempted to measure the life-cycle GHG footprint of shale gas and are valuable from our perspective in framing the marginal impact of shale gas on the GHG intensity of average natural gas-fired electricity. We then build up to a full comparison of the life-cycle emissions between natural gas and coal-fired electricity generation at a national level based on different assumptions and data adjustments in order to assess the impact that the EPA 2011 methodology change on GHG inventory has on the LCA comparison between average U.S. natural gas- and coal-fired electricity generation. We use emissions data for 2008 as a comparable baseline to show the impact of the 2010 and 2011 changes in EPA methane methodology to the life-cycle GHG emissions comparison between coal and natural gas in that year. (Note the Global Warming Potential used throughout this analysis is 25 unless otherwise noted – see Appendix B.) This overview provides a roadmap to follow the logic of our analytic approach.

1. In Exhibit 2, page 10 we compare the most recent bottom-up studies of the LCA of gas from hydraulically fractured shale formations versus coal as a starting point;

2. In Exhibit 4, page 13 we list the baseline EPA data for 2008 on the upstream natural gas emissions expressed as million metric tons of CO_2 equivalent ($MMTCO_2e$).

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[10] Methane remains in the atmosphere for ~9-15 years, compared to 100+ years for CO_2. Methane, however, is much more effective at trapping heat in the atmosphere than CO_2, particularly over 20 year time periods (Please see Appendix B at the end of this report)

[11] Of critical importance, such leaks can be fairly easily mitigated from a technical perspective at reasonable cost, which means that there is scope for improvement

[12] The EPA Greenhouse Gas Reporting Rule gives CH_4 and N_2O emission factors for the combustion of different fossil fuels. For CH_4, emission factors of 0.001 kg/MMBtu of natural gas and 0.011 kg/MMBtu of coal were used. For N2O, emission factors of 0.0001 kg/MMBtu of natural gas and 0.0016 kg/MMBtu of coal were used. The emission factors are in table C-2, page 38 of Subpart C of the rule. (Please see [illegible] GHG MRR Final Rule.pdf)
These were then adjusted using GWPs for CH_4 and N_2O to obtain emissions factors in kg CO_2e/MMBtu. Unless otherwise noted in the paper 100-year GWP values from the IPCC's Fourth Assessment Report (2007) were used, 25 for CH_4 and 298 for N_2O. Using these values, the total GHGs emitted during the combustion of natural gas are 53.07 kg CO_2e/MMBtu (99.90% CO_2, 0.05% CH_4, 0.06% N_2O) and the total GHGs emitted during the combustion of coal are 95.13 kg CO_2e/MMBtu (99.21% CO_2, 0.29% CH_4, 0.50% N_2O)

Step 3: In Exhibit 5, page 14, we adjust these baseline estimates to account for additional factors such as natural gas imports methane emissions from other parts of the industry and other types of emissions associated with natural gas production;

Step 4: In Exhibit 6, page 15, we combine our adjusted upstream and downstream natural gas emissions to derive a normalized life-cycle emissions expressed as kg/MMBTU (volume of greenhouse gases per unit of energy value delivered to the power plant) and compare with coal on an equivalent carbon-dioxide equivalent basis for the electricity sector using 2008 data and the EPA's 2011 methane emissions methodology,

Step 5: In Exhibit 7, page 15, we rerun Step 3 above for 2008 emissions but using the EPA 2010 methane emission methodology from the EPA in order to show the impact of the revisions pre-combustion in kg CO_2e/MMBtu;

Step 6: In Exhibit 8, page 15, we use EPA's 2011 methane emissions methodology to calculate emissions for 2009, the most recent year data available;

Step 7: In Exhibit 10, page 17, we adjust upstream emissions from coal into standard volume units of $MMTCO_2e$ in order to assess the emissions associated with the production and transportation from the mine to the power plant using 2008 data for an apples-to-apples comparison with gas.

Step 8: In Exhibit 11, page 17, we then normalize these upstream coal emission factors into kg CO_2e/MMBtu (emission volume per unit of energy delivered);

Step 9: In Exhibit 12, page 19, we compare the life-cycle emissions of natural gas and coal delivered to the power plant in kg CO_2e/MMMBtu using 2008 data but adjusted for both 2010 and 2011 EPA methane emission factor methodologies for natural-gas to show the impact of EPA's revisions;

Step 10: In Exhibit 13, page 20, we show the LCA in terms of emissions per megawatt-hour of electricity generated from gas and coal using the national average power plant efficiencies for 2008. The life-cycle emissions for gas are 11 percent higher using the updated methodology. The Exhibit shows a six percentage point change with gas producing 47 percent lower emissions than coal using EPA's 2011 methane methodology compared to producing 53 percent lower emissions using EPA 2010 methane methodology based on a 100-year GWP value for methane of 25.

Sensitivity analysis in Appendix B – GWPs: In Appendix B, we show the sensitivities of our LCA to different GWPs.

Overview of Natural Gas Systems and Emission Sources

Between its 2010 and 2011 editions of the Inventory, the EPA significantly revised its methodology for estimating GHG emissions from natural gas systems, resulting in an estimate of methane emissions from Natural Gas Systems in 2008 that was 120 percent higher than its previous estimate. Up until 2010, the Inventory had relied extensively upon emission and activity factors developed in a study by the EPA and the Gas Research Institute in 1996. For the 2011 Inventory, the EPA modified its treatment of two emissions sources that had not been widely used at the time of the 1996 study, but have since become common: gas well completions and workovers with hydraulic fracturing. It also significantly modified the estimation methodology for emissions from gas well cleanups, condensate storage tanks, and centrifugal compressors.

The bulk of the EPA's recent upward revisions of natural gas emissions estimates are related to the production part of the gas value chain. The largest component of the increase is due to revised estimates of methane released from liquids unloading. In some natural gas wells, downhole gas pressure is used to blow reservoir liquids that have accumulated at the bottom of the well to the surface.[13] The revisions also include an increase in the share of gas that is produced from hydraulically fractured shale gas wells and a change in the assumption as to how much of the flow-back emissions are flared. Previously, the EPA assumed that 100 percent of these emissions were flared or captured for sale. The new estimate assumes that approximately one third are flared and another third are captured through "reduced emission completions." Both of these are based on estimated counts of equipment and facility and associated emission factors.

These revisions have caused some to question whether replacing coal with natural gas would actually reduce GHGs, when emissions over the entire life cycles of both fuels are taken into account. Addressing these questions requires an understanding of:

1) The best available data on emissions throughout the life cycles of natural gas and coal;
2) The specific sources and magnitudes of GHG emissions streams for natural gas produced from shale versus conventional formations; and
3) How an increase in the contribution of shale gas to the U.S. natural gas supply might impact the overall life-cycle GHG footprint of natural gas-fired electricity in the future as the marginal skews the average.

Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental shale plays have been a growing source of supply. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas").

Exhibit 1 illustrates the primary sources of GHG emissions during natural gas production, processing, transmission and distribution. The equipment for drilling both oil and gas wells is powered primarily by large diesel engines and also includes a variety of diesel-fueled mobile equipment. Raw natural gas is vented at various points during production and processing prior to compression and transport by pipeline. In some cases, the gas may be flared rather than vented to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a less potent GHG than methane.

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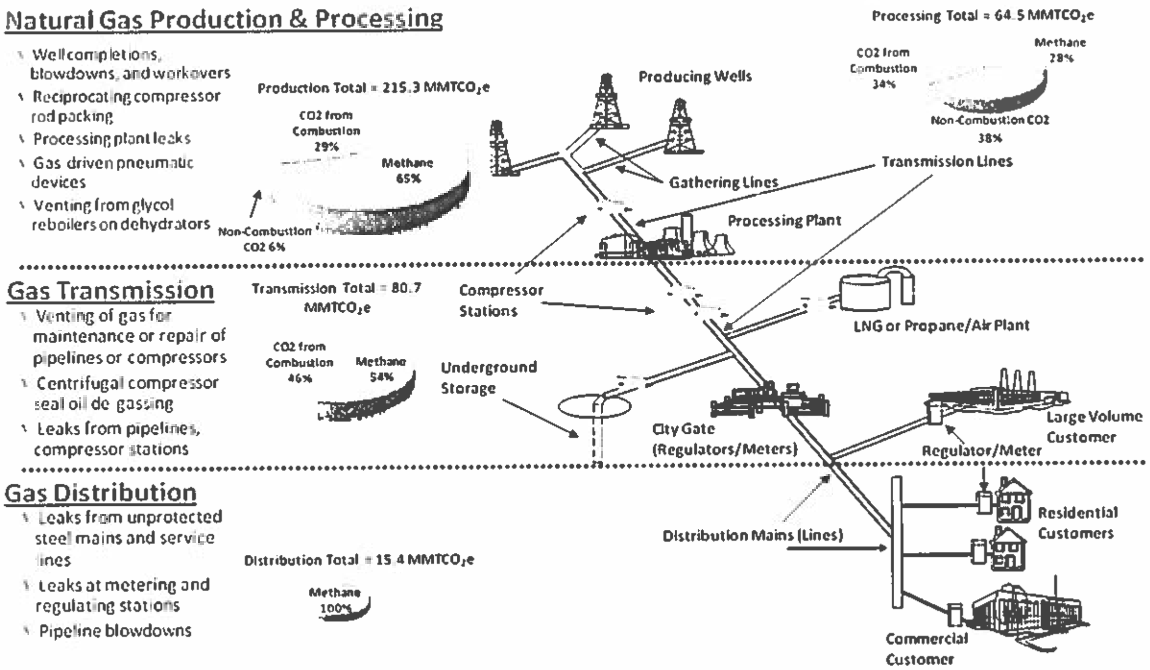
[13] *The technique of blowing out liquids is most frequently used in vertical wells containing "wet" or liquids-rich gas. It is being replaced by many producers with "plunger lifts" that remove liquids with much less gas release. In many shale wells, a technique is used where liquids are allowed to collect in a side section of the well and removed with a pump. EPA, Natural GAS Star, "Lessons Learned: Installing Plunger Lift Systems in Gas Wells," October 2006, available at* [illegible]



Sources: American Gas Association, EPA Natural Gas STAR Program, DBCCA analysis, 2011.

The recent focus of new natural gas development has been shale gas, which currently represents about 14 percent of U.S. domestic production but is expected to reach 45 percent or more by 2035.[14] Most gas-bearing shale formations lie 8,000 to 12,000 feet below the surface and are tapped by drilling down from the surface and then horizontally through the target formation, with lateral drills extending anywhere from 3,000 to 10,000 feet. After drilling is complete, operators hydraulically fracture the shale, pumping fluids at high pressure into the well to stimulate the production of the gas trapped in the target rock formation. Horizontal drilling and pumping water for hydraulic fracturing release additional engine emissions compared to conventional production techniques. In addition, when the produced water "flows back" out of the well, raw gas from the producing formation can be released into the atmosphere at the wellhead.[15]

In both associated and non-associated gas production, water and hydrocarbon liquids are separated from the gas stream after it is produced at the wellhead. The gas separation process may involve some fuel combustion and can also involve some venting and/or flaring. Shale plays in particular are geologically heterogeneous, and the energy requirements to extract gas can vary widely. Moreover, the methane content of raw gas varies widely among different gas formations. Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. This "formation" CO_2 is vented at the gas processing plant and represents another source of GHG emissions along with the combustion emissions from the plant's processing equipment.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the "city gate" hub and then to the power plant. The vast majority of the compressors that pressurize the pipeline to move

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[14] *EIA Annual Energy Outlook 2011. DOE/EIA-0383ER(2011). Energy Information Administration, U.S. Department of Energy.* [illegible]

[15] *The GHG comparison between conventional and shale wells is important given the rapidly evolving industrial landscape with a share shift toward shale wells. For its part, the International Energy Agency (IEA) in a June 2011 Special Report "Are We Entering a Global Age of Gas?" concluded that the LCA emissions of natural gas from shale wells is between 3.5 and 12 percent more than from conventional gas. IEA June 2011, page 64*

the gas are fueled by natural gas, although a small share is powered by electricity.[16] Compressors emit CO_2 emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission. Actual leakage from the pipelines themselves is very small.

Some power plants receive gas directly from transmission pipelines, while others have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some relatively small methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Review of Recent Bottom-Up Life-Cycle Analyses: The Marginal Impact on Emissions

The assessment of how much more methane is released from shale gas production than from conventional production is a key factor in the discussion of possible changes in the life-cycle emissions of natural gas. As the shale gas component of U.S. production increases, a higher marginal greenhouse gas footprint from shale gas would raise the average greenhouse gas footprint of the U.S. natural gas supply overall. On the other hand, changing production technology and regulation could reduce emissions from both shale and other natural gas wells. The life-cycle GHG comparison between shale and conventional natural gas therefore has important implications for stakeholders who are considering policies and investment on the basis of how carbon-intensive natural gas is today and how carbon-intensive it is likely to be in the future.

A number of recent bottom-up life-cycle analyses attempt to quantify the GHG comparison between conventional and shale gas. Exhibit 2 shows the results of several of these analyses and how they compare to our top down analysis, which follows later.[17] Bottom-up figures are taken from studies by Skone, et al. (NETL), Jiang et al. (Jiang), and Howarth, et al. (Howarth). Because these and other life-cycle studies each make different assumptions as to the global warming potential of methane and the product whose greenhouse gas footprint is being measured—some use units of natural gas produced, others use units of natural gas delivered, and still other use units of electricity generated—we have normalized these figures using a GWP of 25. Any remaining variability in the GHG estimates are the result of differences in underlying emissions factors used. Despite differences in methodology and coverage, all of the recent studies except Howarth et al. estimate that life-cycle emissions from natural gas-fired generation are significantly less than those from coal-fired generation on a per MMBtu basis. As can be seen in Exhibit 2, our GHG estimate for average U.S. gas based on EPA's 2011 data (72.3 kg/MMBtu) is very similar to the National Energy Technology Laboratory's (NETL) bottom-up estimate for Barnett Shale gas (73.5 kg/MMBtu).

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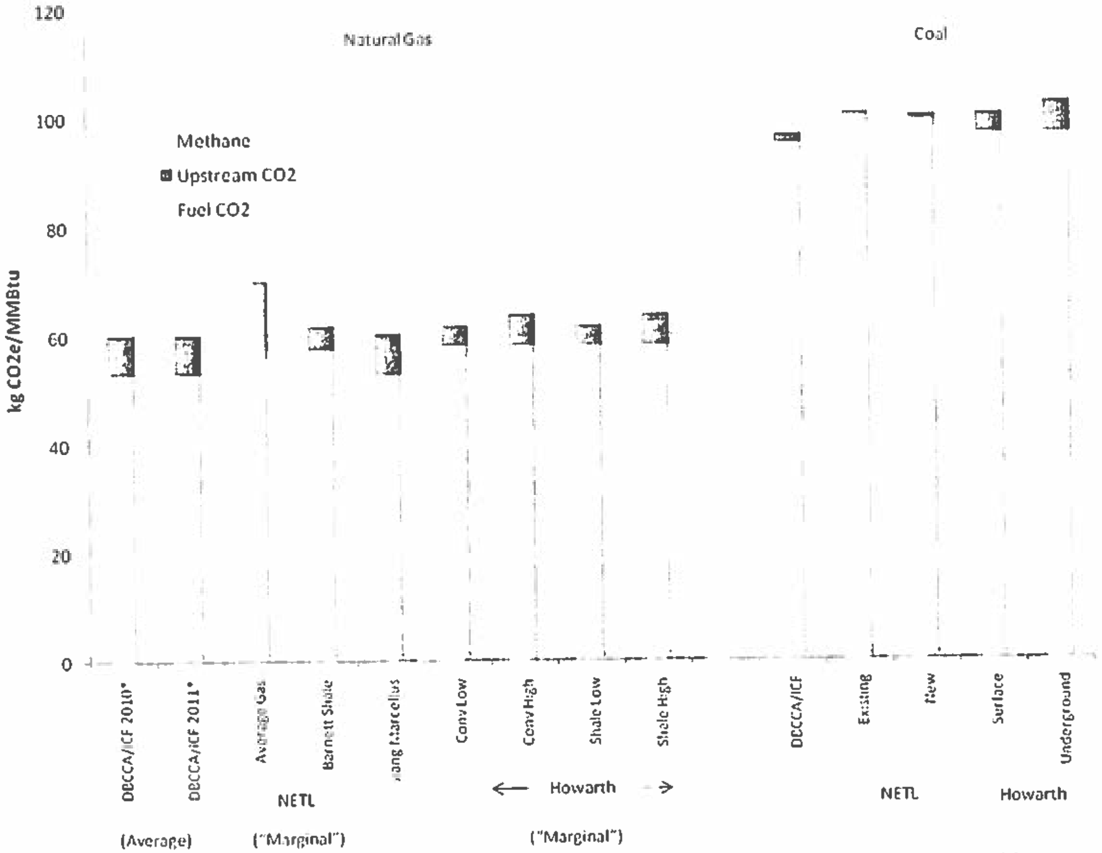
[16] ORNL. Transportation Energy Data Book. Oak Ridge National Laboratory. U.S. Department of Energy. June 2010. [illegible]

[17] The results of the top-down life-cycle analysis conducted in the present study are displayed for reference. Bottom-up figures are taken from studies by Skone, et al. 2011 (NETL), Jiang et al. 2011 (Jiang), and Howarth, et al. 2011 (Howarth). All studies are normalized using a 100-year GWP for methane of 25, and given in kg CO_2e per MMBtu of fuel rather than kg CO_2e per MWh of electricity generated. Most studies use MMBtu of fuel produced as their metric; the present study uses MMBtu of fuel consumed, an explanation of which is given on p. 22.



Source DBCCA Analysis 2011 Note NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study *2011 EPA methodology compared to 2010

Many of these studies draw upon data from the U S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (hereafter "Inventory" or "Greenhouse Gas Inventory). The Inventory, published annually, is the official U S report on GHG emissions to the UN IPCC and the source for much of the analysis of U.S. emissions.[18] The inventory is developed from a variety of public and private data sources on the many different kinds of GHG emission sources in different sectors It uses a combination of "bottom-up" analysis, utilizing counts and characteristics of individual facilities, and "top-down" analysis, such as national data on fuel combustion from the Energy Information Administration (EIA) to calculate CO_2 emissions from combustion, to build an estimate for total U S GHG annual emissions across a range of sectors

Greenhouse gas emissions from natural gas and coal production, processing, transport, and distribution are estimated in the Inventory's "Natural Gas Systems" and "Coal Mining." In the EPA's 2011 edition of the Inventory, Natural Gas Systems were estimated to be the largest source of non-combustion, energy-related GHG emissions in the U S., at 296 million metric tons of CO_2 equivalent (MMT CO_2e) in 2009. Coal mining came in third, with an estimated 85 MMT CO_2e of emissions. Fossil fuel combustion accounted for the vast majority of GHG emissions from the U.S energy sector, with an estimated 1,747.6 MMT CO_2e coming from coal-fired electricity generation alone, while natural gas-fired electricity generation accounted for an additional 373.1 MMT CO_2e (Exhibit 3).[19]

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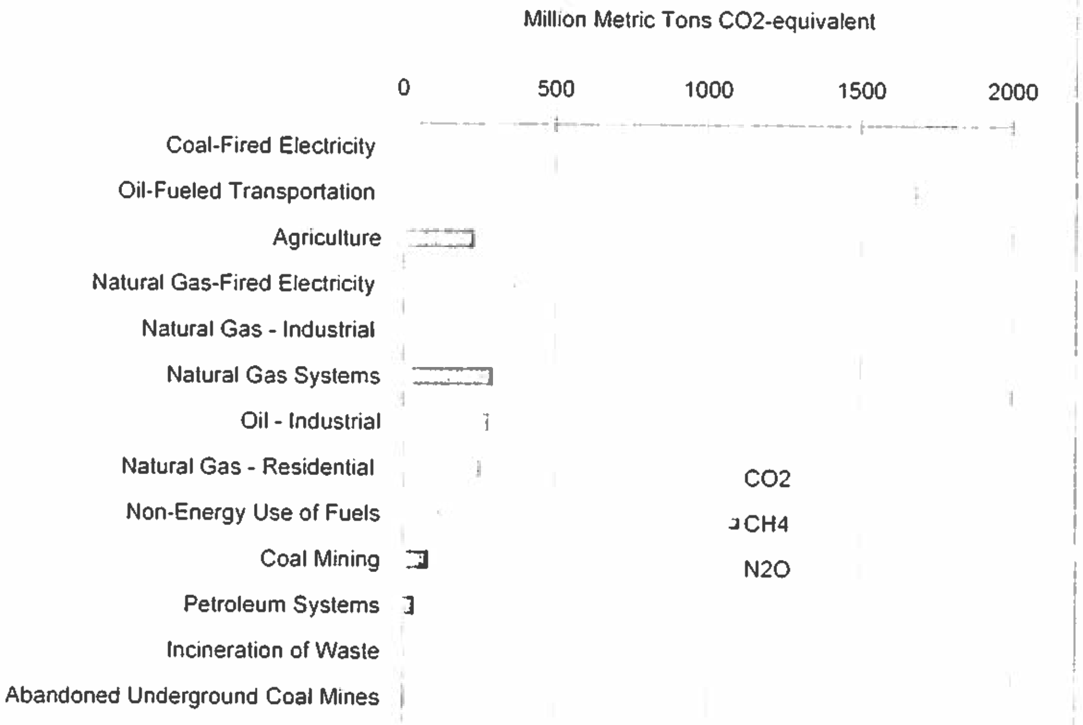
[18] EPA *Inventory of U S Greenhouse Gas Emissions and Sinks 1990-2009* (April 2011) available at [illegible]

[19] All figures given in CO_2 equivalent here and elsewhere assume a global warming potential of 25 for methane unless otherwise noted The EPA's Inventory uses a GWP of 21 for reporting purposes, so these numbers were converted to make them consistent with the GWP used for



These are the highest-emitting energy and agriculture sector source categories for 2009. Source: EPA 2011. Data were adjusted to use most recent IPCC GWPs for CH4 and N2O (25 and 298, respectively).

We draw two main conclusions from our survey of recent bottom-up life-cycle assessments First, **the natural gas industry's practices are evolving rapidly, and better data are essential to ensuring that life-cycle greenhouse gas assessments remain up-to-date and reflect current industry behavior.** All of the bottom-up life-cycle assessments we surveyed identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Among the sources of uncertainty identified were formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers, and formation-specific gas compositions

Second, because shale gas appears to have a GHG footprint some 8 to 11 percent higher than conventional gas on a life-cycle basis per mmBtu based on these bottom up studies that we reviewed, **increased production of shale gas would tend to increase the average life-cycle GHG footprint from U.S. natural gas production if methane emissions from the upstream portion of the natural gas life are unmitigated.** This fact underlines the **importance of implementing the many existing control technologies and practices that can significantly reduce the overall greenhouse gas footprint of the natural gas industry** Many companies are already reducing vented and flared methane emissions voluntarily through the EPA's voluntary Natural Gas STAR program. For example, the Inventory estimates that the completion emissions of methane from two thirds of shale gas production are already being mitigated through flaring or reduced emission completion.[20] If this is correct, then bottom-up life-cycle GHG estimates that do not account for reduced emissions completions are likely too high.

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the main analysis in this paper EPA, *Inventory of U S Greenhouse Gas Emissions and Sinks 1990-2009* (April 2011) available at [illegible]

[20] *Ibid*

Stronger regulations limiting methane and other air pollutant emissions from oil and natural gas operations are also likely to lead to lower overall GHG emissions. Some states already require the adoption of certain methane controls: Wyoming and Colorado, for example, already require "no-flare" or "green" completions and workovers, which are reported to capture 70 to 90 percent of methane vented during completions and workovers following hydraulic fracturing. Because this methane can then be sold, users of green completions have reported payback times of less than one year.[21] Moreover, the EPA released proposed regulations for the gas production sector on July 28, 2011 that are expected to require mitigation of completion emissions from all wells.[22] This regulation is currently in the comment period and is set to be implemented by court order in 1Q12. If these regulations are adopted, there will be little or no difference between the emissions of hydraulically fractured and conventional gas wells.

The remainder of this paper develops a top-down life-cycle greenhouse gas analysis of natural gas and coal for the purpose of determining the impact of recent EPA revisions to methane emissions estimation methodologies on the current comparison between U.S. natural gas and coal-fired electricity.

Natural Gas

This analysis for natural gas includes each of the industry steps described in Exhibit 1 above. (See Appendix A for a detailed methodology.) The source of information for methane emissions and non-combustion CO_2 is the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* (April 2011 release), which includes updated estimates for methane emissions from natural gas production that are approximately twice the level indicated in the previous 2010 edition.[23] This LCA uses the data from both 2010 and 2011 EPA inventory reports to illustrate the effect that the EPA's latest increase in estimated methane emissions has on the overall LCA for gas (as discussed below), which we estimate to be about an 11 percent increase in the life-cycle emissions.

The U.S. Energy Information Administration (EIA) is the primary source for the data on natural gas consumption and associated CO_2 emissions in the various segments of the gas industry (fuel for gas compressors and gas processing plants).[24] In addition to the natural gas, petroleum is used for drill rigs, trucks and other mobile equipment, such as pumps for hydraulic fracturing. This analysis uses information from the Economic Census to estimate non-natural gas energy consumption and associated CO_2 emissions in the production sector.[25]

Sources of methane emissions are many and vary widely. Apart from EIA there are very few sources of aggregated data in the public domain. As noted earlier, the EPA recently increased its estimates significantly for several processes in natural gas production, and better data availability on methane leakage and venting will be critical going forward given the rapidly evolving gas production landscape. On this score, disclosures and reporting of upstream emissions have historically been voluntary. And while there is evidence that large volumes of GHGs are being captured by industry, the actual penetration rates of these voluntary programs is unknown[26].

For example, the EPA Natural Gas STAR program, a voluntary methane mitigation program, reports that its members reduced methane emissions from natural gas systems by 904 billion cubic feet between 2003 and 2009—equivalent to 365 $MMTCO_2e$.[27] This program has identified and documented many methane mitigation measures that could be applied more widely across both industries and are included in the EPA's Inventory of US Greenhouse Gas Emissions

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[21] EPA. Natural Gas STAR Program. "Reduced Emissions Completions. Lessons Learned," available at [illegible], viewed 2 August 2011.

[22] EPA. "Oil and Natural Gas Air Pollution Standards," [illegible] viewed 18 August 2011

[23] *The new EPA data have raised questions on two ends, with some believing the estimates are too high and others believing they are too low. Some comments submitted to the EPA from gas producers about the Draft Inventory question the validity of these revisions, believing them too high. While on the other hand, there are environmental advocacy groups that question whether EPA's "activity factors" used in its methodology accurately represent the preponderance of shale wells being drilled in the Gulf Coast and North East regions, thereby raising the question of whether the emission factors are indeed high enough.*

[24] *EIA. Natural gas navigator. Natural gas gross withdrawals and production.* [illegible]

[25] *U.S. Department of Commerce. Census of Mining 2007. Census Bureau. U.S. Department of Census.*

[26] *Reported 2009 Natural Gas STAR voluntary emission reductions were the equivalent of ~$344 million in revenue (assuming $4/mmBtu gas) and the avoidance of 34.8 mn tonnes CO_2e. http://www.epa.gov/gasstar/accomplishments/index.html#content*

[27] *EPA Natural Gas STAR Program Accomplishments, page 2. http://www.epa.gov/gasstar/accomplishments/index.html*

and Sinks report.[28] Additionally, many mitigation activities are not reported to these programs. It is also possible that the EPA is missing or has underestimated some sources of upstream emissions for both natural gas and coal. Nevertheless, we expect that better information will be available in the spring of 2012 when reporting of data on upstream methane emissions through EPA's GHG Reporting Program commences.

In our LCA, the emission factors for the combustion of natural gas, coal and petroleum includes the CO_2 from complete combustion of the fuel plus the small amounts of nitrous oxide (N_2O) and unburned methane that result from the combustion. The emission factors for fuel combustion are taken from subpart C of the EPA Greenhouse Gas Reporting Program.[29] The N_2O and methane emissions from combustion are less than 1% of the CO_2 emissions. The total emission factors for combustion are:

- Natural gas – 53.07 kg CO_2 e/MMBtu
- Diesel fuel – 74.21 kg CO_2 e/MMBtu
- Coal – 95.11 kg CO_2 e/MMBtu

Exhibit 4 summarizes the data on total upstream GHG emissions calculated for the natural gas sector for the year 2008 using the April 2011 EPA inventory for methane adjusted for a methane GWP of 25 and the EIA data on fuel consumption. According to this inventory, U.S. production, processing, and transport of natural gas emitted 387.0 million tons of CO_2 equivalent ($MMTCO_2e$) in 2008

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

In this analysis, we adjust several factors to more accurately and robustly capture the life-cycle emissions associated with the use of natural gas on a national basis.

First, the emissions estimates account for natural gas production in the United States; however, because 13 percent of natural gas consumed in the U.S. was imported in 2008, we increase the production and processing emissions estimates to account for emissions from gas imports. Of that 13 percent in 2008, 11.7 percent was imported by pipeline from North America, mostly from Canada. The analysis assumes that other North American production operations are similar to those in the United States, so the emissions are increased linearly to account for these imports. In addition, 1.3 percent of the gas supply arrived via liquefied natural gas (LNG) imports. The LNG life cycle includes additional emissions associated with liquefaction, transportation, and regasification from source to use. The LNG portion is escalated by 76 percent to account for these emissions, based on a bottom-up LNG LCA prepared by NETL.[30] These are the most significant modifications made in our analysis, increasing the overall LCA for natural gas by 39 $MMTCO_2e$, or about 10 percent, primarily due to the adjustment for pipeline imports.

A second adjustment relates to methane emissions from distribution lines at local gas distribution companies. Since only 52 percent of the gas used for power generation is delivered by local distribution lines, the methane emissions associated with distribution have been discounted by that amount.[31] This reduces the total emissions by 18 $MMtCO_2e$, or 4 percent.

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[28] *EPA.* Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, *April 2011, available at* [illegible] *p. 152*

[29] *EPA. Greenhouse Gas Reporting Program, Subpart C. U.S. Environmental Protection Agency, http://www.epa.gov/climatechange/emissions/ghgrulemaking.html*

[30] *Skone, T.J. 2010. Life Cycle Greenhouse Gas Analysis of Power Generation Options. National Energy Technology Laboratory. U.S. Department of Energy*

[31] *EIA. EIA-176. "Annual Report of Natural and Supplemental Gas Supply and Disposition". Energy Information Administration. U.S. Department of Energy* [illegible]

A final adjustment is for methane emissions from production of associated gas—gas produced from oil wells. We did this in order to accurately adjust the impact of associated gas in our net import correction. Most oil wells produce some natural gas, and some of this gas is collected and becomes part of the gas supply. The EPA inventory of U.S. GHG emissions estimates that methane emissions from petroleum systems are approximately 30 MMTCO$_2$e per year.[32] Since some domestic natural gas is co-produced with petroleum, these emissions could be considered for inclusion in the LCA of emissions from the natural gas sector.

The associated natural gas produced and the methane emitted during petroleum production, processing, and transport are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. By this assessment it would not be appropriate to count the methane emissions from petroleum production, since they are independent of the production of gas.

On the other hand, associated gas produced from oil wells represents a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the LCA, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production. This calculation is shown in Appendix A and results in an additional 5 MMTCO$_2$e of emissions being added, or a 1.4 percent increase.

Exhibit 5 shows our adjusted total emissions for 2008, which come to 423.8 MMTCO$_2$e compared to the 387.0 baseline. The production segment is the largest contributor to GHG emissions from the natural gas supply chain, accounting for 57 percent of total emissions. Of the different gases, methane accounts for 59 percent of total GHG emissions using a GWP of 25.

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

To compare emissions from coal and natural gas on an apples-to-apples basis, the emissions are normalized to the amount of GHG per million Btu (MMBtu) of *natural gas delivered to consumers* using EIA data for gas deliveries[33]. Some LCAs normalize to GHG per unit of natural gas *produced*, which includes associated gas that is reinjected into the producing formation as well as natural gas liquids that are removed during gas processing and gas lost through fugitives and venting, in addition to gas actually delivered to consumers such as power plants. Using delivered rather than produced natural gas results in a slightly higher overall figure for life-cycle emissions but depicts more accurately the energy that is actually available to power plants. The total normalized upstream emissions are 19.2 kg CO$_2$e/MMBtu of natural gas delivered. (See Exhibit 6.) As discussed earlier, the emissions for combustion of the natural gas at the power plant are 53.1 kg CO$_2$e/MMBtu, so the total life-cycle GHG emissions at the point of use are 72.3 kg/MMBtu. Of this, the upstream emissions are 30 percent, 60 percent of which are from methane.

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[32] *Inventory of US Greenhouse Gas Emissions and Sinks 1990-2009, EPA 430-R-11-005, April 2011 page 27*

EIA. Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

Doing the same calculation with the lower methane emissions estimated in the prior year's EPA inventory yields a value of 12.0 kg CO_2e/MMBtu for the upstream emissions. (See Exhibit 7) Including the end-use gas consumption, total life-cycle emissions are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

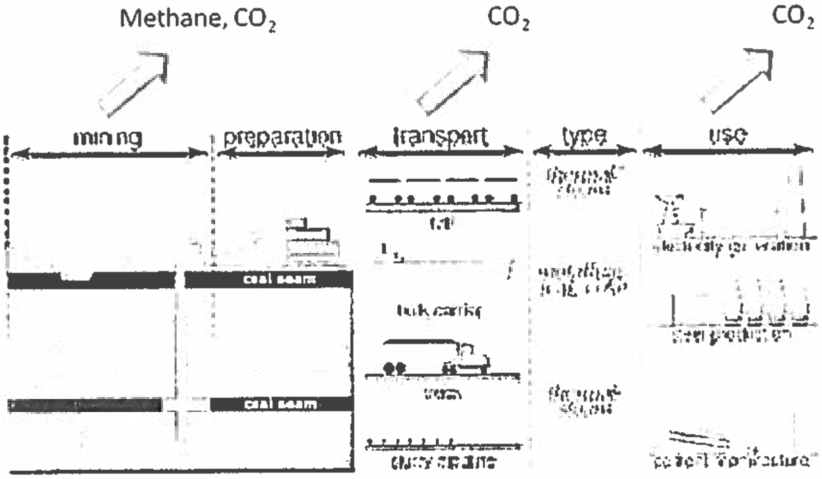
	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Finally, Exhibit 8 applies the most recent EPA data to calculate the life-cycle emissions for 2009 using the 2011 methane emissions methodology. This is the most recent year for which data are available. The 2009 emissions are quite similar to the emissions calculated for 2008 using the same methodology (73.1 vs 72.1 expressed as kg CO2e/MMBtu).

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	8.4	0.6	3.0	12.0
Processing	1.1	1.1	1.0	3.2
Transmission	2.4	0.0	1.6	4.0
Distribution	0.8	0.0	0.0	0.8
Upstream Total	12.8	1.7	5.6	20.1
Fuel Combustion	0.0	0.0	53.1	53.1
Total	12.8	1.7	58.7	73.1

Coal

The production and distribution of coal is simpler to analyze than that of natural gas because there are fewer steps in production and processing (Exhibit 9). Coal is produced in the U.S. from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. This analysis estimates the direct and indirect emissions of the mining processes from Economic Census data[34]. (For detailed calculations of the coal LCA, see Appendix A.)



Source: University of Wyoming

Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, which is a safety hazard, and in some cases the methane can be recovered for use or flared to reduce GHG emissions. The U.S. GHG Inventory estimates the methane emissions from coal mining. Coal mines that are no longer active (i.e., are "abandoned") release methane as well: 7.0 $MMTCO_2e$ in 2008 (at 25 GWP). This would add an additional 0.4 kg CO_2e/MMBtu to the coal LCA but is not included here since we do not have similar data on methane emissions from abandoned gas wells.

Data on coal transportation by mode are available from the Economic Census[35]. More than 90 percent of coal is transported by train, with the remainder transported by barge, truck, or various combinations of these modes. This analysis derives the energy consumption per ton-mile from several sources to calculate CO_2 emissions. (See Appendix A.)

The United States is a net exporter of coal by 4 percent, so the production data are adjusted downward by that amount. Table 6 shows the adjusted upstream GHG emissions for coal, totaling 117.8 $MMTCO_2e$.

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[34] *U.S. Department of Commerce. Census of Mining 2007. Census Bureau. U.S. Department of Census*

[35] *Ibid*

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

As with the natural gas LCA, this analysis "normalizes" total emissions by the energy delivered to coal consumers (more than 90% power of whom are power generators), or 1,147 million short tons of coal in 2008. This yields a normalized upstream emission factor of 4.8 kg CO_2e/MMBtu consumed. (See Exhibit 11.) This value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg/MMBtu, bringing the total end-use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane comprises 63 percent of the upstream emissions, the upstream component is only 5 percent of the total, with CO_2 emissions from the combustion of the coal itself being the dominant factor in the total life-cycle emissions.

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

Finally, life-cycle GHG emissions per MMBtu of fuel delivered to power plants are normalized to GHG emissions per MWh of electricity generated to account for the difference in coal and natural gas power plant efficiencies. In 2008, essentially all coal-fired electricity in the United States was generated by steam-turbine power plants, which combust fuel to boil water and use the resulting steam to drive a turbine.[36] Many coal plants are run almost all the time at full capacity to provide baseload power. Technology has improved over the past several decades and new plants have improved combustion efficiencies, but many active plants in the U.S. fleet were built before 1970 and are less efficient.

By contrast, natural gas is used in a range of power plant technologies, each of which fills a different role in the electricity dispatch. In 2008, only 12 percent of natural gas-fired electricity was generated by steam-turbine plants, most of which were built before 1980 and are relatively inefficient. An additional 9 percent was generated by simple-cycle gas turbines, relatively inefficient plants that are used to provide peaking power during limited periods. Since 2000, a large portion of new natural gas capacity additions have been combined-cycle units, which use waste heat from gas turbines to run steam turbines.

Combined-cycle plants have superior heat rates and may be used to provide baseload or intermediate power, depending on the particular grid and the price of gas. In 2008, 79 percent of gas-fired electricity was generated by combined-cycle plants. Two coal plants in the U.S. currently gasify coal to generate electricity in a combined-cycle configuration, but such plants, called Integrated Gasification Combined Cycle (IGCC) plants, have very low market penetration today.

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[36] *All 2008 generation data from Energy Information Administration (EIA), Form EIA-923, 2008*

The heat rate (the amount of fuel in Btus needed to generate a kilowatt-hour of electricity) of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity.[37] Unless otherwise specified, this analysis uses heat rates representing the average efficiency of existing power plants in the U S. fleet.

- **Average efficiency of existing capital stock:** National average values are based on EIA data for total gas or coal consumption for generation and total generation by each fuel. The heat rates are 8,044 Btu/kWh (41 percent efficiency) for gas generation and 11,044Btu/kWh (31 percent efficiency) for coal generation.

A sensitivity analysis comparing life-cycle emissions results using average heat rates and heat rates representative of new natural gas and coal plants is shown in Appendix A (Exhibit A-12).

- **Efficiency of new plants:** In its *Annual Energy Outlook 2010*[38], EIA provides a value for a new plant in 2009, and for future plants that accounts for future cost reductions from learning and production efficiencies ("nth" plant). The values used here are the average of the two values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency).

Summary of Results and Sensitivity Analysis for Top=Down Analysis

Exhibit 12 compares the calculated LCA emissions (by GHG) for gas delivered to power plants for (a) natural gas using the EPA 2010 methodology, (b) natural gas using the EPA 2011 methodology, and (c) coal. In all cases, the emissions are dominated by CO_2 from final combustion of the fuel at the power plant. The upstream emissions are larger for gas, and the power plant combustion emissions are higher for coal. The LCA for coal is dominated by the CO_2 from the coal combustion itself. The upstream component is larger for natural gas, and methane is a larger component of the emissions. Using the increased methane emission estimate for gas from the 2011 methodology results in the LCA for natural gas being 11 percent higher than with the 2010 estimate. The gas life-cycle value using the 2011 methodology is 28 percent lower than the coal value.

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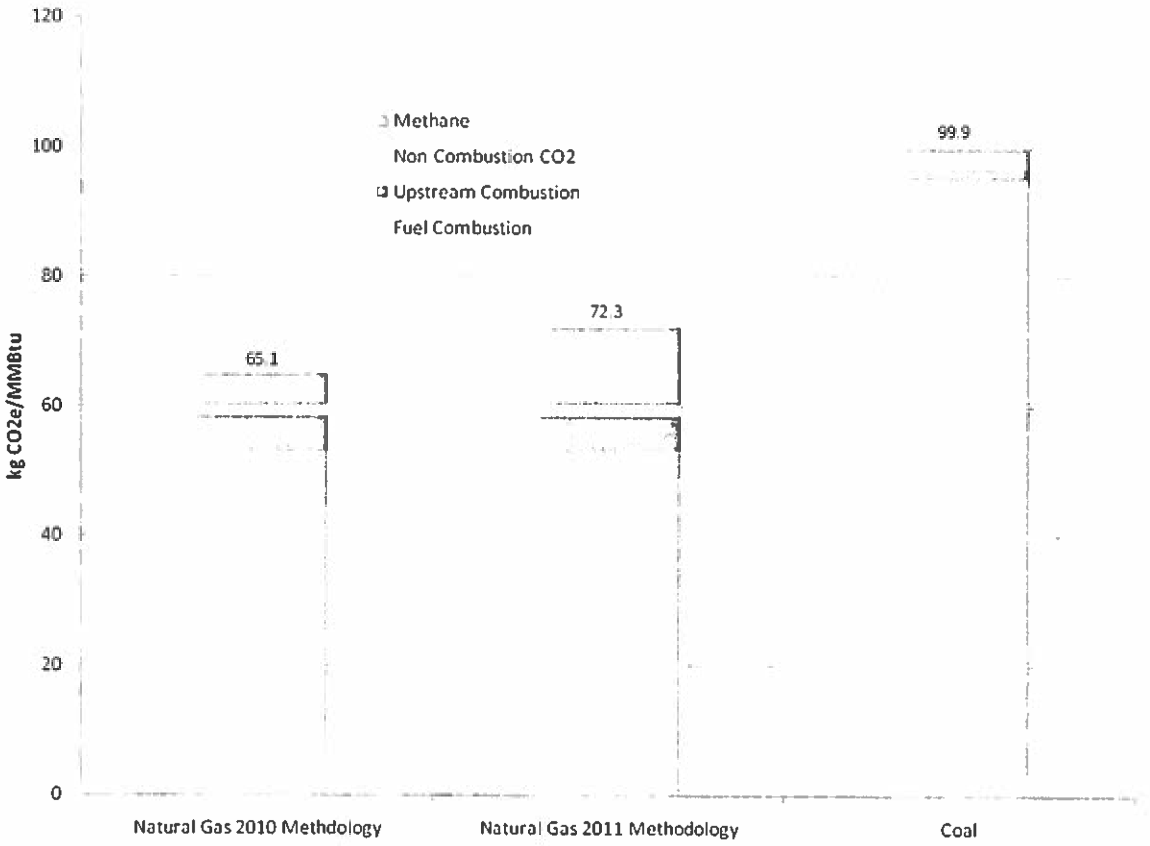
[37] The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate in Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.

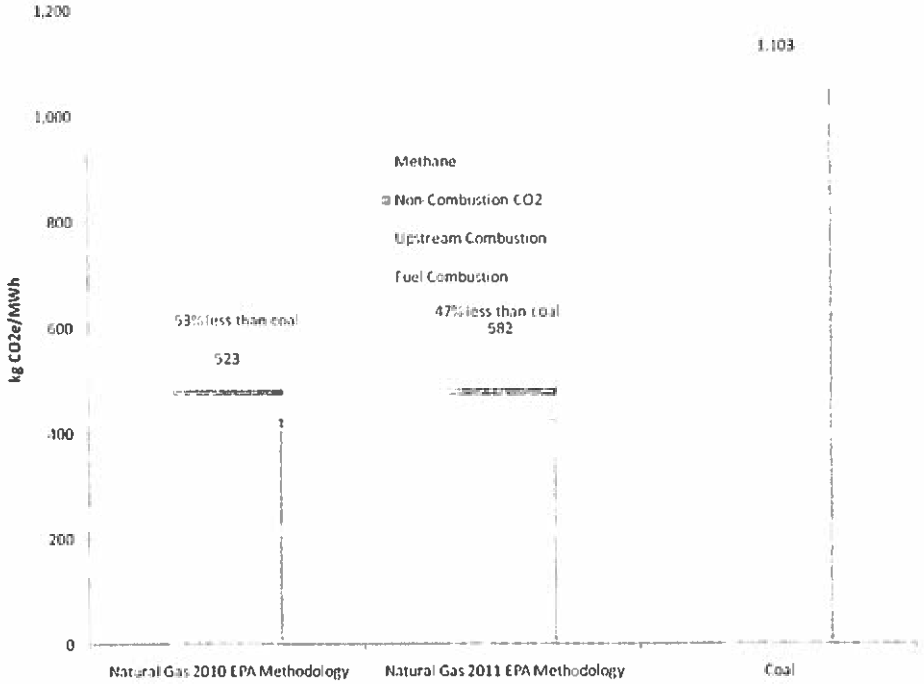
[38] *EIA. Assumptions to the Annual Energy Outlook 2010 – Table 8-2.* DOE/EIA-0554(2010). *Energy Information Administration, U S Department of Energy.* [illegible]

Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal



Source DBCCA Analysis 2011

Exhibit 13 shows the LCA in terms of GHG emissions per megawatt-hour of electricity generated from gas and coal, using the national average power plant efficiencies. The gas value using the 2011 EPA methane emissions estimates is 582 kg CO_2e/MWh—or 11 percent higher than the 523 kg CO_2e/MWh calculated using data for 2010 methodology. The value for coal is 1,103 kg CO_2e/MWh. Because coal plants are on average less efficient than gas plants, the difference between gas and coal is greater than the fuel-only comparison at the burner tip prior to combustion and conversion to electricity. **Natural gas-fired electricity, using the 2011 methodology, has 47 percent lower life-cycle GHG emissions per unit of electricity than coal-fired electricity.**



Source: DBCCA Analysis 2011

Our top-down LCA of natural gas and coal-based generation using publicly available data shows that the EPA's recent revision of methane emissions increases the life-cycle GHG emissions for natural gas-fired electricity by about 11 percent from estimates based on the earlier values. Our conclusion is that, on average, natural gas-fired power generation emits significantly fewer GHGs compared to coal-fired power generation. Life-cycle emissions for natural gas generation using new EPA estimates are 47 lower than for coal-based generation when using a GWP of 25. The impact of different GWPs to our LCA can be found in Appendix B.

Nevertheless, methane, despite its shorter lifetime than carbon dioxide, is of concern as a GHG. Compared to coal-fired generation, methane emissions, including a large venting component, comprise a much larger share of natural-gas generation's GHGs. And while measurement of upstream emissions and public disclosure of those emissions still has room for improvement, methane emissions during the production, processing, transport, storage, and distribution of natural gas can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas.

Appendix A
Detailed Methodology and Calculations

Natural Gas

The natural gas LCA addresses emissions from extraction through electricity generation for 2008. The primary data sources are the EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* and EIA data on natural gas consumption[39]. Exhibit A-1 shows the basic information on total emissions by industry segment for 2008. The methane emissions are from the EPA Inventory and adjusted from a GWP of 21 to a GWP of 25. The non-combustion CO_2 emissions are from the same source and include CO_2 from combustion of flared gas and the formation CO_2 vented from gas processing plants. The CO_2 from combustion is primarily from the EIA data on gas consumption in the gas industry. The gas consumed in the production segment is the "lease gas" reported by EIA, which is gas consumed in the producing areas. EIA also reports "vented and flared gas," which is assumed here to be all flared but is already included in the EPA category of non-combustion emissions. The "processing" category includes the "plant gas" reported by EIA, and "transmission" includes the pipeline and distribution fuel reported by EIA. The total upstream emissions from these sources are 387.0 $MMTCO_2e$ based on a 100 year GWP of 25.

Detailed data collection and verification, as well as LCA harmonization to common metrics and system boundaries are critical for improving the rigor of LCA analysis. The National Renewable Energy Laboratory's Joint Institute for Strategic Energy Analysis, www.jisea.org, will be conducting such an evaluation in the coming months, which may improve upon the historical data sets used by EPA.

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

There are several additions to this basic information. First, there are some electric driven compressors on the pipeline network. This electricity consumption of 2,936.6 million kWh is from the ORNL *Transportation Data Book*[40]. (That estimate is based on a fixed share of 1.5 percent of the natural gas consumption.) The emission factor for electricity throughout the analysis is 603 kg CO_2/MWh, calculated from EIA data on total generation and CO_2 emissions. This electricity consumption adds 1.8 $MMTCO_2e$ to the pipeline emissions. There is also diesel fuel, gasoline and other petroleum fuel used in gas drilling and production that is not separately reported by EIA. This information is collected by the Economic Census[41]**Error! Bookmark not defined.** but only by NAICS code and only every 10 years (the latest reporting year is 2007). The four relevant NAICS codes are: 211111 (crude petroleum and natural gas extraction); 211112 (natural gas liquid extraction), 213111 (drilling oil and gas wells); and 213112 (support activities for oil and gas operations).

Three of these codes (excepting NGL extraction) combine data for oil and gas operation. The gas portion is calculated based on the gas share of U.S. producing oil and gas wells (55.4 percent) or active drilling rigs (83.2 percent). Also, the Census lists expenditures only by fuel type. The actual consumption is estimated from the expenditures based on average price for each fuel. The consumption is then converted to CO_2 emissions using the emission factors from the EPA GHG Reporting Program. These emissions are then escalated from 2007 to 2008 based on EIA data for production (3.9 percent increase). The calculations are summarized in Exhibit A-2. Total emissions for this segment are 7.2 $MMTCO_2e$.

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[39] *EIA. Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

[40] *ORNL. Transportation Energy Data Book. Oak Ridge National Laboratory. U.S. Department of Energy. June 2010.*
[illegible]

[41] *U.S. Department of Commerce. Census of Mining 2007. Census Bureau. U.S. Department of Census*

Energy Consumption (MMBtu)						
NACS		Distillate	Gasoline	Other	Residual Oil	Undistributed
211111	Extraction	29,055,998	10,031,608	--	6,539,144	8,502,932
211112	NGL Extraction	288,585	352,861	66,627	--	168,613
213111	Drilling	10,014,334	3,808,638	551,713	3,967,479	5,446,747
213112	Support	20,671,552	13,157,404	893,604	7,166,105	4,389,137

CO_2 Emission Factors		Distillate	Gasoline	Other	Residual Oil	Other
		73.96	70.22	62.98	75.1	62.98

CO_2 Emissions ($MMTCO_2e$)						
211111	Extraction	2.1	0.7	0	0.5	0.5
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.7	0.3	0	0.3	0.3
213112	Support	1.5	0.9	0.1	0.5	0.3

Gas Share of Emissions ($MMTCO_2e$)						
21111	Extraction	1.8	0.6	0	0.4	0.4
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.4	0.1	0	0.2	0.2
213112	Support	1.3	0.8	0	0.4	0.2

Source: EPA, ORNL, Census Bureau, DBCCA Analysis 2011

Another adjustment is for methane emissions from "associated" gas produced from oil wells. Most oil wells produce gas, much of which is captured and delivered to consumers. The EPA *Inventory of U.S. GHG Emissions* estimates methane emissions from petroleum systems to be approximately 30 $MMTCO_2e$ per year.

Since some domestic natural gas is co-produced with petroleum, one could consider all of these emissions be included in the life-cycle analysis of emissions from the natural gas sector. However, the natural gas produced and the methane emissions are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. One could also therefore maintain that it is not appropriate to count the methane emissions from petroleum production toward gas use, since they are independent of the production of gas and are related to petroleum consumption.

On the other hand, associated gas produced from oil wells is a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the life-cycle analysis, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production.

The EPA inventory separates the methane emissions from petroleum systems at the wellhead oil separator. Methane emitted on the oil side downstream from the separator is allocated to the petroleum side, and methane emitted on the natural gas side is allocated to the natural gas side. The part that must be allocated here is the upstream production emissions, of which the largest components are miscellaneous venting and fugitives and venting from gas-powered pneumatic devices. The approach in this analysis is to simply allocate these emissions based on the energy value of oil versus gas produced from these wells.

According to the EIA, the gross production of natural gas from petroleum wells in 2008 was 5.7 trillion cubic feet (Tcf)[42]. However, much of this gas (3.3 Tcf) was not gathered for sale but was reinjected into the producing formation. Some of the gas is reinjected to push more oil out of the formation. Most of the reinjection (3.0 Tcf) is from Alaska production where there is no pipeline to bring the gas to market. It is reinjected as a means of storage until the time when a pipeline may be built to the lower 48 states. In any case, the associated gas actually produced for potential sale is 2.5 Tcf. On an energy basis, this is 20 percent energy value of the net associated gas plus the 1.8 billion barrels of U.S. oil production in 2008.

Of the methane emission sources in petroleum production, we include pneumatic device venting, combustion and process upsets, miscellaneous venting and fugitives, and wellhead fugitives. Tank venting is not included because it is purely related to oil production. Total methane emissions for these sources in 2008 were 25.6 MMTCO$_2$e, according to the EPA inventory. Taking 20 percent of this total gives 5.0 MMTCO$_2$e of additional methane emissions to allocate to the natural gas LCA, increasing the unadjusted emission baseline by 1.4 percent.

With these additions (electricity, non-gas fuel, and methane from petroleum systems), total upstream gas production emissions are 402.0 MMTCO$_2$e.

The total emissions are then adjusted for imports. The calculations above include emissions for U.S. production, but a net 13 percent of natural gas was imported in 2008. Of this, 11.7 percent was imported by pipeline from Mexico and Canada (mostly the latter). This analysis assumes that production processes are similar throughout North America, so the production emissions are escalated by 11.7 percent to account for the pipeline imports. The remaining 1.3 percent of imports were LNG imports. LNG has a higher LCA than conventional gas due to gasification, liquefaction, and transportation processes. The LCA for LNG is estimated at 176 percent of conventional gas based on the LCA performed by NETL[30] The production emissions for the LNG component are increased by this amount. The adjustment for imports is the largest adjustment, increasing the emissions by about 39 MMTCO$_2$e, or 10 percent.

The other adjustment in this analysis is related to fugitive methane emissions from gas distribution lines at local gas distribution companies (LDCs). Methane emissions from local distribution lines are 35.6 MMTCO$_2$e (at 25 GWP), but many power plants receive gas deliveries directly from interstate pipelines rather than via local distribution lines. Relatively few power plants actually purchase gas from LDCs, but some receive gas deliveries from the LDCs. The EIA-176 survey[43] provides data on deliveries by LDCs to electric generators; however, these reported deliveries total 6.5 Tcf, which is almost equal to total gas consumption for electricity generation. This is because intrastate pipeline deliveries in California, Texas, and Florida are included in the EIA-176 survey. Excluding these three states, 59 percent of gas to electric generators is delivered by LDCs. Based on this, only 59 percent of the distribution company methane emissions are included in the adjusted values. This adjustment decreases the emissions by about 17 MMTCO$_2$e, or 4 percent. Exhibit A-3 shows the adjusted final upstream GHG emissions for natural gas: 423.8 MMTCO$_2$e. Methane emissions account for more than half of the total.

	Methane	Non-Combustion CO$_2$	CO$_2$ and N$_2$O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

These total emissions are then normalized to kg CO$_2$e/MMBtu of delivered natural gas based on the EIA data on natural gas delivered to consumers; 21.4 trillion cubic feet (Tcf). The total normalized upstream emissions are 19.2 kg CO$_2$e/MMBtu. (See Exhibit A-4.) The emissions for combustion of the gas at the point of use are 53.07 kg

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[42] *EIA. Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

[43] *EIA. EIA-176. "Annual Report of Natural and Supplemental Gas Supply and Disposition". Energy Information Administration, U.S. Department of Energy.* [illegible]

CO_2e/MMBtu (including N_2O and unburned methane), so the total life-cycle GHG emissions at the point of use are 70.4 kg CO_2e/MMBtu. Of this, the upstream emissions are 24 percent and methane is slightly over half of the upstream component.

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

The same methodology is applied using EPA's 2010 estimate of methane emissions, to show the effect of the updated, increased 2011 methane emission estimate. Exhibits A-5 and A-6 show the total and normalized emissions for this case. The normalized upstream emissions with the old data are 12.0 kg CO_2e/MMBtu. Including the end-use gas combustion, total life-cycle emissions including end-use combustion are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	25.9	9.7	62.2	97.8
Processing	17.7	24.4	22.2	64.2
Transmission	46.9	0.1	37.2	84.2
Distribution	18.3	0.0	0.0	18.3
Total	108.8	34.2	121.5	264.6

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Coal LCA

The upstream energy consumption for coal production is calculated using the 2007 Economic Census[44] data on fuel and electricity consumption in the same way as the non-gas fuel for gas production. In this case, there is a separate NAICS code for coal production, so no adjustments are necessary. The same CO_2 emission factors and the emission factor for electricity use are used as for the data on gas production. (See Exhibit A-7.) The values are adjusted from 2007 to 2008 based on the production in each year—a 2.2 percent increase. The total CO_2 emissions from energy consumption for coal production are 14.0 $MMTCO_2e$. Methane emissions from coal mines of 67.1 $MMTCO_2e$ (79.9 at 25 GWP) are taken from the EPA GHG inventory. Methane from abandoned coal mines is not included.

	Coal	Distillate	Natural Gas	Gasoline	Residual Oil	Other	Electricity (MWh)
MMBtu	3,607,020	52,597,178	2,487,920	4,846,529	25,739,212	2,039,820	11,444,477
Kg CO2/MMBtu	94.38	73.96	53.02	70.22	75.10	62.98	603.01
MMTCO2e	0.34	3.89	0.13	0.34	1.93	0.13	6.90

The estimate of transportation emissions is based on the Commodity Flow Summary[45] developed by the U.S. Department of Transportation and Census Bureau, which provides information on ton-miles of coal transported by different modes. Rail is the primary mode of transportation, with rail-only accounting for 91 percent of the ton-miles and rail and other modes (truck and barge) accounting for the remainder. This analysis applies a ton-mile fuel consumption factor[46, 47, 48] to calculate fuel consumption and converts the fuel consumption to CO_2 using the same EPA emission factors used for other sectors. (See Exhibit A-8.) For mixed mode, rail or barge are assumed to account for 75 percent of the ton-miles and truck for 50 percent. Most coal is delivered via dedicated equipment—e.g., a coal unit train travels only to and from the mine to the power plant. Thus, the fuel consumed in returning empty to the mine must be included. This analysis assumes 100-percent empty return as part of the energy consumption, with the empty fuel consumption being one-third of the loaded consumption based on the weight of the empty vehicle. The total consumption calculated is 23.9 $MMTCO_2$.

Mode	Ton-Miles (million)	Fuel Consumption (ton-mi/gal)	GHG Emissions (MMTCO2)	Round-Trip Emissions (MMTCO2)
Truck	14,002	110.00	1.28	1.67
Rail	773,290	480.00	16.26	21.13
Water	6,548	730.00	0.09	0.12
Truck and rail	785	388.00	0.02	0.03
Truck and water	7,257	575.00	0.13	0.17
Rail and water	26,994	605.00	0.45	0.59
Other multiple modes	4,353	480.00	0.09	0.12
Other and unknown modes	2,567	480.00	0.05	0.07
Total	835,796		18.38	23.89

In the case of coal, the U.S. is a net exporter of about 4 percent of its production, so the total production emissions are adjusted downward by this amount to calculate the emissions attributable to coal consumed in the U.S. Exhibit A-9 shows the final adjusted upstream emissions: 117.8 $MMTCO_2e$.

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[44] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

[45] *U.S. Department of Transportation, Research and Innovative Technology Administration, Bureau of Transportation Statistics and U.S. Census Bureau, 2007 Commodity Flow Survey*

[46] *Federal Railroad Administration, "Comparative Evaluation of Rail and Truck Fuel Efficiency on Competitive Corridors", November 19, 2009*

[47] *Army Corps of Engineers, "Waterborne Commerce Statistics Center",* [illegible]

[48] *American Railroad Association*

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

These values are then normalized by the total 2008 consumption of coal in the U.S. of 1,147 million tons of coal, assuming an average heating value of 10,250 Btu/lb.[49] This yields a normalized upstream emission factor of 4.3 kg CO_2/MMBtu consumed. (See Exhibit A-10.) The value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg CO_2e/MMBtu, bringing the total end use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane is still 63 percent of the upstream emissions, the upstream component is only 4 percent of the total, with the CO_2 emissions from the coal itself being the dominant factor.

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

The efficiency[50] of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity. This analysis looks at two values:

- **National average efficiency values** based on EIA data[51, 52, 53, 54] for total gas or coal consumption for generation and total generation by each fuel. (See Exhibit A-11.)
- **Efficiency[55] for new power plants** assumed by the EIA in its *Annual Energy Outlook 2010*[30]. EIA provides a value for a new plant in 2009 and for subsequent plants ("nth plant") of each type for which the cost may be lower due to learning and production improvement. The values used here are the average of the values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency). (See Exhibit A-12.)

	Energy Consumption (Quads)	Generation (Billion kWh)	Heat Rate (Btu / kWh)	Efficiency
Gas	7	883.00	8,044.00	0.42
Coal	22	1,986.00	11,044.00	0.31

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[49] *EIA. Annual Coal Data. Energy Information Administration. U.S. Department of Energy.* [illegible]

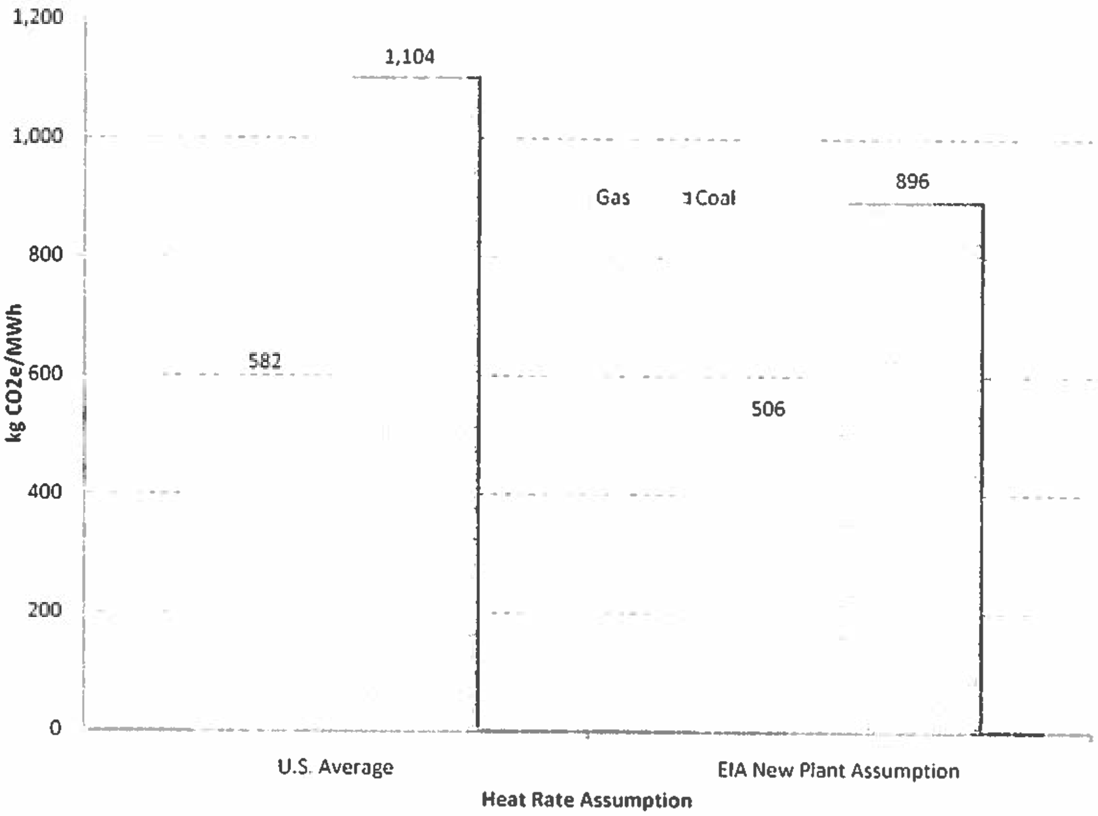
[50] *The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate is Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.*

[51] *EIA, Electric Power Monthly. Energy Information Administration. U.S. Department of Energy.* [illegible]

[52] *EIA, Electric Power Monthly. Energy Information Administration. U.S. Department of Energy.* [illegible]

[53] *EIA, Annual Energy Review. Energy Information Administration. U.S. Department of Energy.* [illegible]

[54] *EIA. Quarterly Coal Report. U.S. Department of Energy.* [illegible]



Source: DBCCA analysis, 2011.

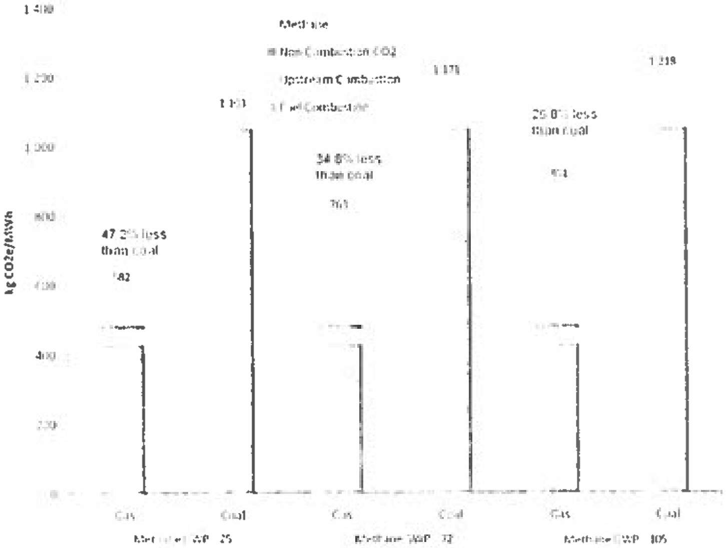
Appendix B
Effect of Global Warming Potential (GWP)

Methane is a potent GHG and its effect varies depending on the lifetime over which it is evaluated. The IPCC uses a 100 year lifetime for its analysis and a 100 year GWP of 25 for methane. Others believe that short-lived GHGs should be evaluated on a 20 year lifetime.

In its recently completed study on natural gas, MIT explains the reasons that a 100 GWP is commonly used:

> *"Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for CO_2), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100- and 500-year integration periods. The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades. An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison. A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than CO_2, and its combination of potency and short life yields the 100-year GWP used in this study."*[56]

In addition, scientific work continues on the appropriate GWPs for different GHGs. Although the IPCC 20-year GWP for methane is 72, new work by Shindell et al[57] proposes a 20-year GWP of 105 for methane. Exhibit B-1 above shows the effect of different methane GWPs on the LCA using the EPA 2011 methodology. Since methane is a much larger component of the LCA for natural gas, the GWP has a much larger effect on gas than coal. Going from the 100 year GWP to the 20-year GWP of 72 increases life-cycle emissions for natural gas by 31 percent and for coal by only 6 percent. At the GWP of 72, the power plant emissions for natural gas are 35 percent lower than those for coal. At the 105 GWP, the emissions for the gas-fired plant are 27 percent lower than those for coal.



Source: DBCCA Analysis 2011

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[56] The Future of Natural Gas. Moniz, Ernest J., Jacoby, Henry D., Meggs, Anthony J M. (Study co-chairs). MIT Energy Initiative. 2011

[57] Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326 716–718

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I-023945-1.1

Climatic Change
DOI 10.1007/s10584-011-0061-5

LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Received: 12 November 2010 / Accepted: 13 March 2011

Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

Electronic supplementary material The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material, which is available to authorized users.

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142 × 10^3 to 425 × 10^3 m^3 per well. Using the mean drill-out emissions estimate of 280 × 10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85 × 10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45 × 10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a] Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b] Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c] Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d] Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e] Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during “liquid unloading.” Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

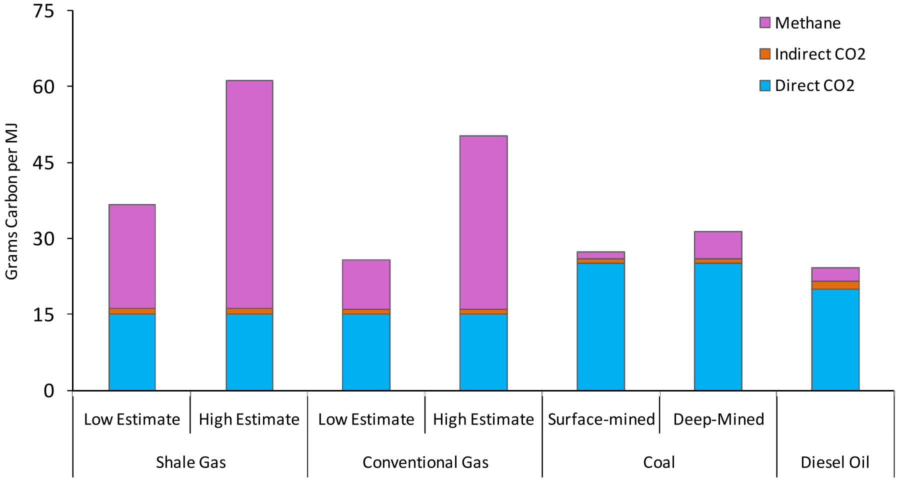
Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

A. 20-year time horizon



B. 100-year time horizon

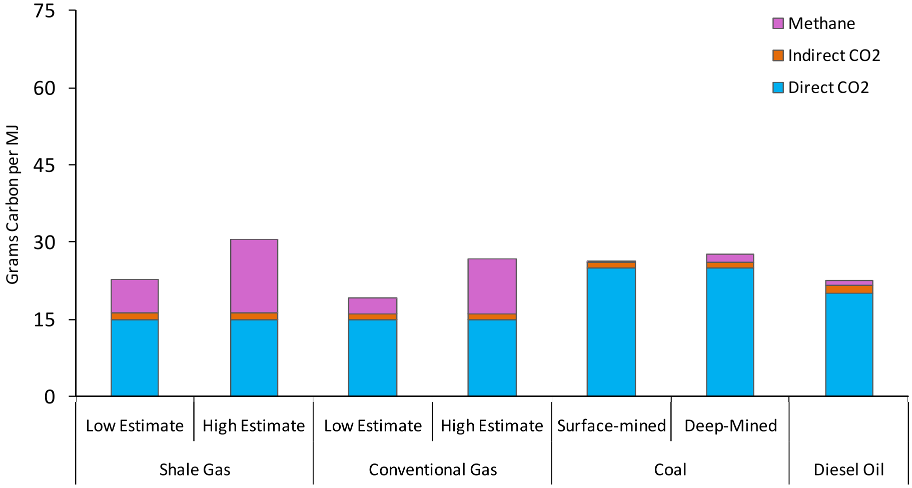


Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that ’green’ technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

Acknowledgements Preparation of this paper was supported by a grant from the Park Foundation and by an endowment funds of the David R. Atkinson Professorship in Ecology & Environmental Biology at Cornell University. We thank R. Alvarez, C. Arnold, P. Artaxo, A. Chambers, D. Farnham, P. Jamarillo, N. Mahowald, R. Marino, R. McCoy, J. Northrup, S. Porder, M. Robertson, B. Sell, D. Shrag, L. Spaeth, and D. Strahan for information, encouragement, advice, and feedback on our analysis and manuscript. We thank M. Hayn for assistance with the figures. Two anonymous reviewers and Michael Oppenheimer provided very useful comments on an earlier version of this paper.

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2011 Environ. Res. Lett. 6 034014

(http://iopscience.iop.org/1748-9326/6/3/034014)

IOP PUBLISHING ENVIRONMENTAL RESEARCH LETTERS
Environ. Res. Lett. **6** (2011) 034014 (9pp) doi:10.1088/1748-9326/6/3/034014

Life cycle greenhouse gas emissions of Marcellus shale gas

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Received 13 January 2011
Accepted for publication 14 July 2011
Published 5 August 2011
Online at stacks.iop.org/ERL/6/034014

Abstract

This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

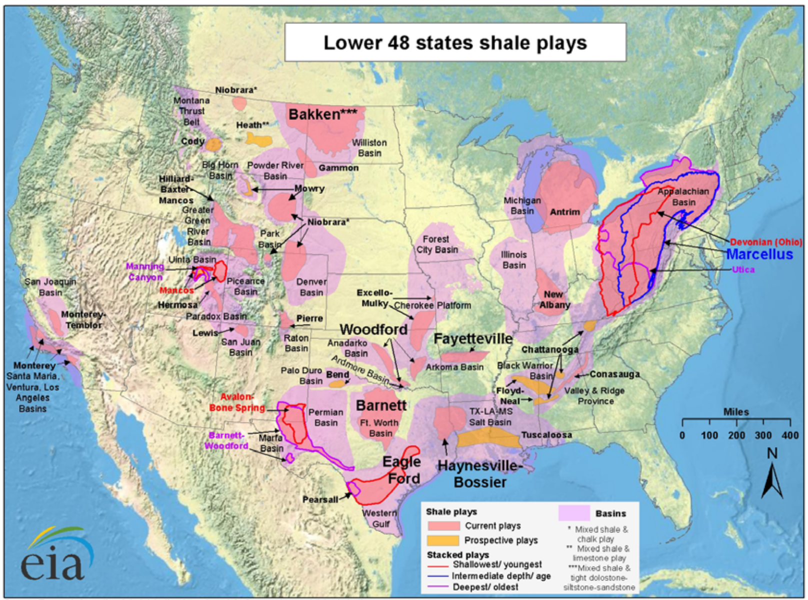
Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas

S Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1. Shale gas plays and basins in the 48 states (source: US Energy Information Administration 2011a, available at http://www.eia.gov/oil_gas/rpd/shale_gas.jpg).

natural gas use including increased natural gas fired electricity generation, use as an alternative transportation fuel, and even exporting as liquefied natural gas. To date most shale gas activity has been in the Barnett shale in Texas. However, the immense potential of the Marcellus shale has stimulated increased attention. The shale play has an estimated gas-in-place of 1500 Tcf or 42 000 Mm^3, of which 262–500 Tcf or 7400–14 000 Mm^3 are thought to be recoverable (Hill *et al* 2004, US DOE 2009).

Advancements in horizontal drilling and hydraulic fracturing, demonstrated successfully in the Barnett shale and first applied in the Marcellus shale in 2004, have enabled the recovery of economical levels of Marcellus shale gas. After vertical drilling reaches the depth of the shale, the shale formation is penetrated horizontally with lateral lengths extending thousands of feet to ensure maximum contact with the gas-bearing seam. Hydraulic fracturing is then used to increase permeability that in turn increases the gas flow.

In this study, life cycle greenhouse gas (GHG) emissions associated with the Marcellus shale gas production are estimated. The difference between GHG emissions of natural gas production from unconventional Marcellus gas wells and average domestic wells is considered to help determine the environmental impacts of the development of shale gas resources. The results of this analysis are compared with life cycle GHG emissions of average domestic natural gas pre-Marcellus and imported liquefied natural gas. In addition domestic coal and Marcellus shale for electricity generation are compared. Other environmental issues may also be of concern in the Marcellus shale development, including disruption of natural habitats, the use of water and creation of wastewater as well as the impacts of truck transport in rural areas. However these environmental issues are outside the scope of our analysis and are not addressed in this paper.

In estimating GHG emissions, we include GHG emissions of carbon dioxide, methane and nitrous oxide. We converted the GHG emissions to carbon dioxide equivalents according to the global warming potential (GWP) factors reported by IPCC. We use the 100-year GWP factor, in which methane has a global warming potential (GWP) 25 times higher than carbon dioxide (IPCC 2007).

2. Marcellus shale gas analysis boundaries and functional unit

The boundary of our analysis and the major process steps included in our estimates are shown in figure 2. Final life cycle emission estimates are reported in grams of carbon dioxide equivalent emissions per megajoule of natural gas ($\mathrm{g\ CO_2e/MJ}$) produced. Each of the individual processes in the natural gas life cycle has an associated upstream supply chain and is included in this study to provide a full assessment of GHG emissions associated with Marcellus shale gas. The sources of GHG emissions considered in the LCA include: emissions from the production and transportation of material involved in the well development activities (such as trucking water); emissions from fuel consumption for powering the drilling and fracturing equipment; methane leaks and fuel combustion emissions associated with gas production, processing, transmission, distribution, and natural gas combustion.

The life cycle of Marcellus shale natural gas begins with a ‘preproduction phase’ that includes the well site investigation, preparation of the well pad including grading and construction of the well pad and access roads, drilling, hydraulic fracturing, and well completion (Soeder and Kappel 2009). After this preproduction phase is completed, the well becomes operational and starts producing natural gas. This natural gas can require additional processing to remove water, $\mathrm{CO_2}$ and/or

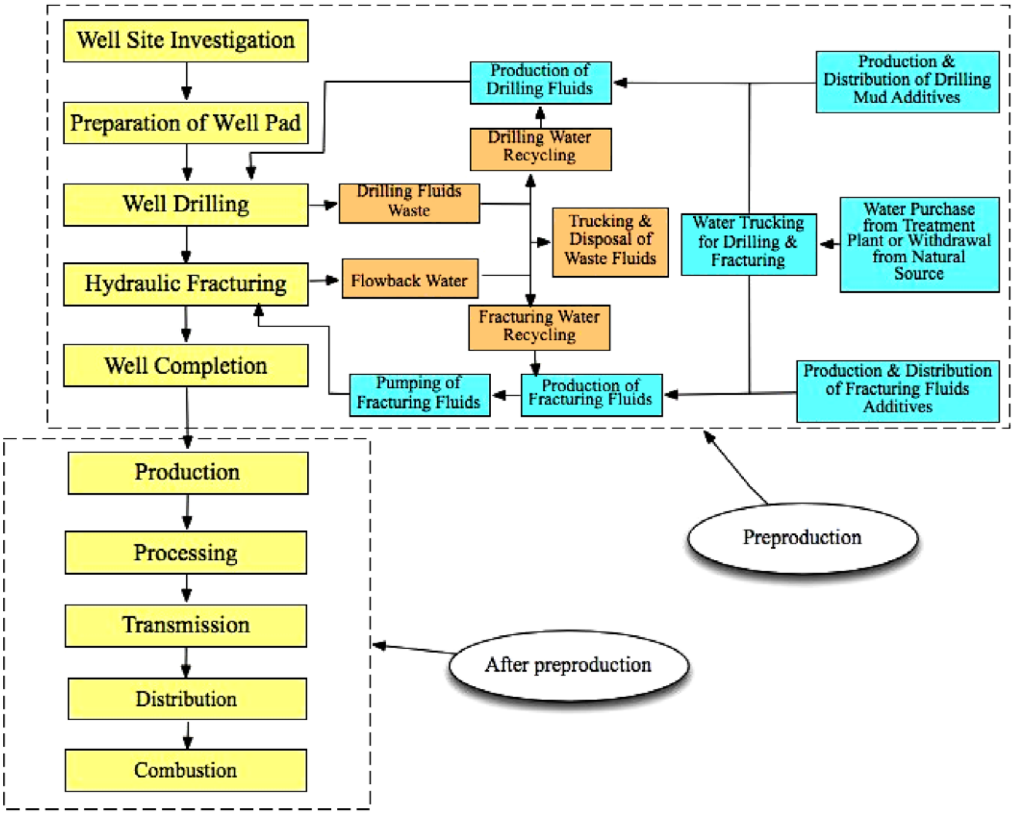


Figure 2. Analysis boundaries and gas production processes.

natural gas liquids before it enters the natural gas transmission and distribution system, which delivers it to final end users. For this work we assume that the GHG emissions for production, transmission, distribution and combustion of Marcellus shale natural gas are similar to average domestic gas sources as estimated by Jaramillo *et al* (2007) and further developed and updated by Venkatesh *et al* (2011).

Finally, natural gas has many current and potential uses including electricity generation, chemical feedstock, and as a transportation fuel. Modeling these uses allows comparisons of different primary energy sources. Here we model its use for power generation since it is the largest single use of natural gas in the US (US EIA 2011a, 2011b).

As previously mentioned, this study integrates GHG emissions from the life cycle of water associated with Marcellus shale gas production. Large amounts of water are consumed in the drilling and hydraulic fracturing processes (preproduction phase). Hydraulic fracturing uses fluid pressure to fracture the surrounding shale. The fracturing fluid consists of water mixed with a number of additives necessary to successfully fracture the shale seam. The source of the water varies and can be surface or ground water, purchased from a local public water supplier, or reused fracturing water. In this study we assume 45% of the water is reused on site and the original sources are surface water (50%) and purchased from a local water treatment plant (50%). Regardless of the water source used to produce the hydraulic fracturing fluid, trucks transport the water for impoundment at the well pad. In addition, flowback water (hydraulic fracturing fluid that returns to the surface) and produced water must be trucked to the final disposal site. This water is assumed to be disposed of via deep well injection. A detailed description of the method and data sources used to estimate the GHG emissions associated with all these stages is presented in section 3.

Marcellus shale gas production is in its infancy. Thus, industry practice is evolving and even single well longevity is unknown. Assumptions related to production rates and ultimate recovery have considerable uncertainty. Below, we include a sensitivity analysis for a wide range of inputs parameters.

This study does not consider any GHG emissions outside of the Marcellus shale gas preproduction and production processes. Natural processes or development actions such as hydraulic fracturing might lead to emissions of the shale gas external to a well, particularly in the case of poorly installed well casings (Osborn *et al* 2011). Any such external leaks are not included in this study.

3. Methods for calculating life cycle greenhouse gas emissions

Our study used a hybrid combination of process activity emission estimates and economic input–output life cycle assessment estimates to estimate the preproduction GHG emission estimates (Hendrickson *et al* 2006, CMU GDI 2010). Emissions from production, processing and transport were adapted from the literature. We include emissions estimates based on different data sources and reasonable

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. Emissions from Marcellus shale gas preproduction

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

extensive sensitivity analysis over a range of flow rates and well lifetimes, as discussed below.

The EIO-LCA (CMU GDI 2010) model was used to estimate GHG emissions from the construction of the access road and the multi-well pad. These costs were estimated using the utility price cost estimation method (RSMeans 2005). The size of an average Marcellus well pad is reported as being between 2 and 6 acres and typically between 4 and 5 acres (16 000 and 20 000 m^2) during drilling and fracturing phase (NY DEC 2009, Columbia University 2009). The costs of constructing this pad are estimated to be \$3.0–\$3.3 million per well pad in 2002 dollars (see the supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail). Using these costs as input, GHG emissions associated with well pad construction are estimated with the EIO-LCA (CMU GDI 2010) model.

Greenhouse gas emissions associated with drilling operations were calculated by two methods; (1) using the drilling energy intensity (table 1) and the life cycle diesel engine emissions factor of 635 g CO_2e per hp–hr output (Sheehan *et al* 2000), and (2) using drilling cost data and the EIO-LCA model (CMU GDI 2010). The EIA estimated the average drilling cost for natural gas wells in 2002 to be \$176 per foot (including the cost for drilling and equipping the wells and for surface producing facilities) (US EIA 2008). Emissions associated with the production of the drilling mud components were based on data from the SimaPro life cycle tool and the EIO-LCA economic model (PRé Consultants 2007, CMU GDI 2010).

Hydraulic fracturing associated GHG emissions result from the operation of the diesel compressor used to move and compress the fracturing fluid to high pressure, the emissions associated with the production of the hydraulic fracturing fluid, and from fugitive methane emissions as flowback water is captured. The last category of emissions is discussed separately below. Energy and emissions associated with the hydraulic fracturing process were modeled by using vendor specific diesel data along with the emission factor described above. The emissions of hydraulic fracturing fluid production are estimated with EIO-LCA model, based on the price of additives and fracturing fluid composition (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail).

There may be significant GHG emissions as a result of flaring and venting activities that occur during well casing and gathering equipment installation. The natural gas associated with the hydraulic fracturing flowback water is flared and vented. Flaring is used for testing the well gas flow prior to the construction of the gas gathering system which transport the gas to the sales line. Well completion emissions depend on the flaring/venting time, gas flow rate during well completion, the ratio of flaring to venting, and flaring efficiency. Uncertainty/variability analysis was conducted to investigate the effect of flaring/venting time, gas flow rate during fracturing water flowback, and flaring per cent on the well completion emissions. For those well completions with the collection facilities in place, gas is flared for between 12 and 24 h, due to necessary flowback operations. In wells where the appropriate gas gathering system as a tie to the gas sales line is not available for the gas during fracturing water flowback, the flaring or venting can occur for between 4 and 15 days as shown in table 2 (NY DEC 2009). In our model, we assumed the gas release rate during well completion equals the initial 30 day gas production rate for the base case and considered a scenario with both venting and flaring (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for details).

3.2. *Emissions from Marcellus shale gas production to combustion*

GHG emissions for production, processing, transmission, distribution and combustion of Marcellus shale natural gas are assumed to be similar to the US average domestic gas system that have been estimated previously (Jaramillo *et al* 2007). Jaramillo *et al* (2007) estimates were updated to include the uncertainty and variability in life cycle estimates and recalculated with recent and/or more detailed information by Venkatesh *et al* (2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. Methane leakage rates throughout the natural gas system (excluding the preproduction processes previously discussed) are a major concern and our analysis has an implied fugitive emissions rate of 2%, consistent with the EPA natural gas industry study (US EPA 1996, 2010).

Venkatesh *et al* (2011) estimated the mean emission factors used in this study: 9.7 g CO_2e/MJ of natural gas in production; 4.3 g CO_2e MJ for processing; 1.4 g CO_2e/MJ for transmission and storage; 0.8 g CO_2e/MJ for distribution; and 50 g CO_2e/MJ for combustion.

3.3. *Emissions associated with the life cycle of water used for drilling and hydraulic fracturing*

Water resource management is a critical component of the production of Marcellus shale natural gas. Chesapeake Energy (2010) indicates that 100 000 gallons of water are used for drilling mud preparation. Two to six million gallons of water per well are required for the hydraulic fracturing process (Staaf and Masur 2009). About 85% of the drilling mud is reused (URS Corporation 2010). The flowback and recycling rates are used to estimate the total volume of water required. About 60–65% of this hydrofracturing fluid is recovered (URS Corporation 2010). For the flowback water, a recycle rate from 30 to 60% can be achieved (Agbaji *et al* 2009). The rest of the flowback water is temporarily stored in the impoundment and transported off site for disposal. Base case assumptions for these parameters are shown in table 2.

Emissions associated with drilling water use and hydraulic fracturing water use result from water taken from surface water resources or a local public water system; truck transport to the well pad, and then from the pad to disposal via deep well injection. It is assumed that no GHG emissions are related

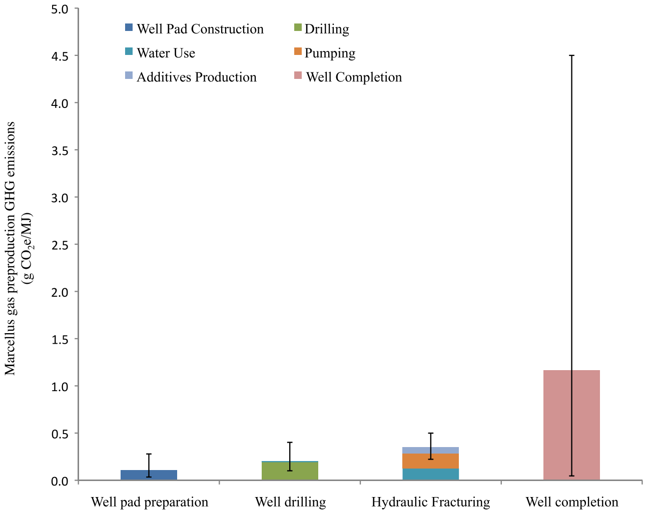


Figure 3. GHG emissions from different stages of Marcellus shale gas preproduction.

with producing water if it comes from surface water resources. For the water purchased from a local public water system, the emission factor for water treatment is used, which is estimated to be 3.4 g CO_2e/gallon of water generated according to Stokes and Horvath (2006). The energy intensity for transportation of liquids via truck is assumed to be 1028 Btu/ton mile for both forward and back-haul trips, as given in the GREET model (Wang and Santini 2009). In this study we assume that separate round trips are needed to transport the freshwater to the pad and to remove wastewater to the disposal site. This is to say that trucks bring in the freshwater from the source and return to the source empty; trucks also collect the wastewater from the well site and return to the well site empty. The life cycle emission factor (wells to wheels) for diesel as a transportation fuel is 93 g CO_2e/MJ (Wang and Santini 2009).

To estimate transport emissions associated with water taken from surface streams and water purchased from the local public water system, we used spatial analysis (ArcGIS) to estimate the distance from the surface water source to the well pad using well operational data and geographical information from Pennsylvania Department of Environmental Protection (2010). We depicted the overall distribution pattern of Marcellus wells under drilling and production in PA and NY in June 2010 by GIS. The distance from the well site to the surface water source is assumed to be 5 miles or 8 km in the base case of the model and the same transportation distance is also assumed for the water purchased from local public water system. We assumed an equal probability for sourcing water between surface water and the local public water system.

The trucking distance between well site and deep well injection facility was also estimated by GIS (PA DEP 2010). The average value of 80 miles or 130 km as determined by GIS was used in the base case.

4. Results for the base case

A total of 5500 t CO_2e is emitted during 'preproduction' per well. This is equivalent to 1.8 g CO_2e/MJ of natural gas produced over the lifetime of the well. Figure 3 depicts the GHG emissions by preproduction stage and by source. As can be seen, the completion stage has the largest GHG emissions, which result from flaring and/or venting. The error bars represent the limits of the 90% confidence interval of the emissions from each stage based on the uncertainty analysis.

A recent EPA report addressing emissions from the natural gas industry reported that 177 t of CH_4 is released during the completion of an unconventional gas well (US EPA 2010). This estimate is consistent with the analysis here and falls within the range estimated by our study, 26–1000 t of CH_4 released per completion and a mean value of 400 t of CH_4 released per completion. In our model, this methane released during the well completion is either flared with a combustion efficiency of 98% or vented without recovery.

Adding the preproduction emissions estimate to the downstream emission estimated by Venkatesh *et al* (2011) results in an overall GHG emissions factor of 68 g CO_2e/MJ of gas produced (figure 4). The life cycle emissions are dominated by combustion that accounts for 74% of the total emissions.

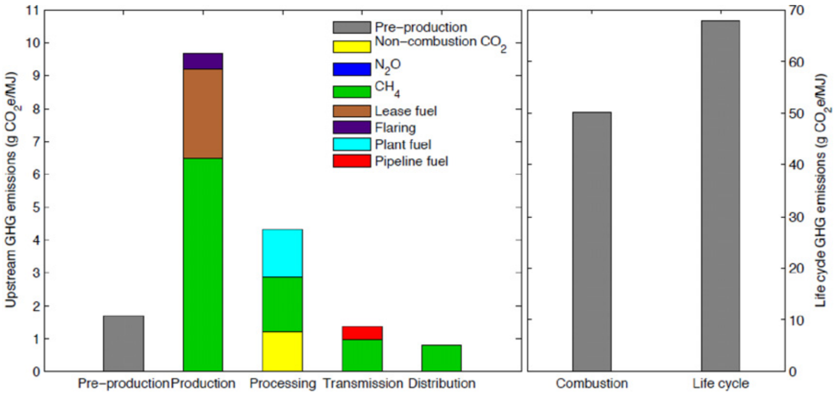


Figure 4. GHG emissions through the life cycle of Marcellus shale gas. (Preproduction through distribution emissions are on left scale; combustion and total life cycle emissions are on right scale. No carbon capture is included after combustion.)

Table 3. Uncertainty analysis on Marcellus gas preproduction.

Life cycle stage	Mean ($g\ CO_2e/MJ$)	Standard deviation ($g\ CO_2e/MJ$)	COV	90% CI-L (%)	90% CI-U (%)
Well pad preparation	0.13	0.1	0.72	58	131
Drilling	0.21	0.1	0.50	51	95
Hydraulic fracturing	0.35	0.1	0.24	37	42
Completion	1.15	1.8	1.53	96	287
Total	1.84	1.8	0.96	67	179

Table 4. Sensitivity of emissions from wells with different production rates and lifetimes. (Source: author calculations.)

Average gas flow (MMscf/day)	Lifetime (years)	Emissions from preproduction ($g\ CO_2e/MJ$)	Preproduction % contribution to life cycle emissions of Marcellus shale gas (%)	Total life cycle emissions ($g\ CO_2e/MJ$)
10	25	0.1	0.1	65.3
10	10	0.1	0.2	65.3
10	5	0.3	0.4	65.5
3	25	0.2	0.3	65.4
3	10	0.5	0.7	65.7
3	5	0.9	1.4	66.1
1	25	0.6	0.8	65.8
1	10	1.4	2.1	66.6
1	5	2.8	4.1	68.0
0.3	25	1.8	2.7	67.0
0.3	10	5	6.6	69.8
0.3	5	9.2	12.4	74.4

5. Sensitivity and uncertainty

Our results are subject to considerable uncertainty, particularly for the production rates and well lifetime. Table 3 summarizes the uncertainty analysis on the emission estimates for preproduction based on the distribution of parameters used.

Table 4 addresses model sensitivity to different estimates of ultimate gas recovery from wells, investigating the impact of different production rates and lifetimes. At high production rates and long well lifetimes the preproduction GHG emissions are normalized over higher volumes of natural gas than when using low flow rates and short well lifetimes. Comparing the case of 10 MMscf/day with a 25-year well lifetime to 0.3 MMscf/day with a 5-year well lifetime, table 4 shows that the emissions go from 0.1 to 9.2 g CO_2e/MJ. The overall life cycle emissions change from 65 to 74 g CO_2e/MJ. However, the preproduction emissions are less than 15% of the total life cycle emissions in all cases.

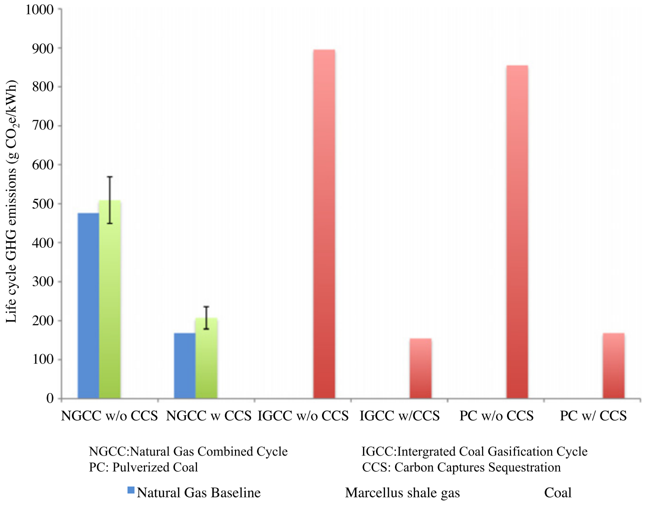


Figure 5. Comparison of life cycle GHG emissions from current domestic natural gas, Marcellus shale gas and coal for use in electricity production.

6. Comparison with coal for power generation

Marcellus shale gas emissions can be compared to alternative energy sources and processes when using a common metric such as electricity generated. Currently coal power plants are used to generate base load. Natural gas power plants, especially inefficient ones, are used to provide regulation services to balance supply and demand at times when base load power plants are insufficient or there is high-frequency variability in load or from renewable resources. Natural gas combined cycle (NGCC) plants could be used to generate base load thus competing directly with coal to provide this service. For this reason our comparison includes the emissions associated with using Marcellus shale gas in a NGCC power plant (efficiency of 50%) and the emissions from using coal in pulverized coal (PC) plants (efficiency of 39%) and integrated gasification combined cycle (IGCC) plants (efficiency of 38%). The results of these comparisons can be seen in figure 5. For this comparison point values are used for the life cycle GHG emissions of coal-based electricity. The error bars found in figure 5 represent the low and high emissions values for Marcellus shale gas, based on the assumptions of well production rate and well lifetime. The high-emission scenario assumes a 5-year well with 0.3 MMscf/day production rate while the low-emission scenario, assumes a 25-year well with 10 MMscf/day production rate. Also shown in figure 5 are the life cycle emissions of electricity generated in power plants with carbon capture and sequestration (CCS) capabilities (efficiency of 43% for NGCC with CCS; efficiency of 30% for PC with CCS; efficiency of 33% for ICGG with CCS).

In general, natural gas provides lower greenhouse emission for all cases studied whether the gas is derived from Marcellus shale or the average 2008 domestic natural gas system. When advanced technologies are used with CSS then the emissions are similar and coal provides slightly less emissions. This implies that the upstream emissions for natural gas life cycle are higher than the upstream emissions from coal, once efficiencies of power generation are taken into account (Jaramillo *et al* 2007).

The comparison of natural gas and coal for electricity allows us to investigate the impact of three additional model uncertainty components including the choice of leakage rate, GWP values, and re-refracking of a Marcellus gas well. This study assumes a 2% production phase leakage rate based on the volume of gas produced (US EPA 2010, Venkatesh *et al* 2011). Assuming the average efficiency of 43% for natural gas fired electricity generation and 32% for coal fired plants the fugitive emissions rate would need to be 14% (resulting in a life cycle emission factor for Marcellus gas of 125 g CO_2e/MJ) before the overall life cycle emissions including those of electricity generation would be greater than coal. This is an exorbitantly high leakage rate and to put it into perspective, using 2009 dry natural gas production estimates and the average wellhead price, we calculate that the economic losses a would total around $11 billion. If we convert our data to the 20-year GWP the break-even point is reduced to 7% because of the higher impacts attributed to methane. Finally, we modeled a single hydraulic fracturing event occurring during well preproduction (figure 3). Above we calculated that the break-even emission factor that would make coal and natural electricity generation the same is 125 g CO_2e/MJ of natural gas. With the current emissions estimate for Marcellus gas of 68 g CO_2e/MJ, and a hydraulic fracturing event (and its associated flaring and venting emissions) contributing 1.5 g CO_2e/MJ to this estimate, more than 25 fracturing events would need to occur in a single well before the decision between coal and natural gas would change.

7. Comparison with liquefied natural gas as a future source

In 2005 EIA suggested that domestic natural gas production and Canadian imports would decline as natural gas consumption increased. EIA predicted that liquefied natural gas (LNG) imports would grow to offset the deficits in North American production (US EIA 2011a, 2011b). As a result of the development of unconventional natural gas reserves, EIA has changed their projections. The Annual Energy Outlook 2011 reference case (US EIA 2011a, 2011b) predicts that increases in shale gas production, including Marcellus, will more than offset the decline in conventional natural gas and decreasing imports from Canada and will allow for increases in natural gas consumption. Since shale gas is projected to be the largest component of the unconventional sources of future natural gas production, it seem appropriate to compare its emissions to those of the gas that would be used if shale gas were not produced. Venkatesh *et al* (2011) estimated the life cycle GHG from LNG imported to the US to have a mean of 70 g CO_2e/MJ, These results are based on emissions due to production and liquefaction in the countries of origin, shipping the gas to the US by ocean tanker, regasification in the US and its transmission, distribution and subsequent combustion. On average, the emissions of Marcellus shale gas were about 3% lower than LNG. As with the overall Marcellus gas results, there is considerable uncertainty to the comparisons. However, we conclude that as these unconventional sources of natural gas supplant LNG imports, overall emissions will not rise.

8. Conclusion

The GHG emission estimates shown here for Marcellus gas are similar to current domestic gas. Other shale gas plays could generate different results considering regional environmental variability and reservoir heterogeneity. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus gas preproduction. These preproduction emissions, however, are not substantial contributors to the life cycle estimates, which are dominated by the combustion emissions of the gas. For comparison purposes, Marcellus shale gas adds only 3% more emissions to the average conventional gas, which is likely within the uncertainty bounds of the study. Marcellus shale gas has lower GHG emissions relative to coal when used to generate electricity.

Acknowledgments

We gratefully acknowledged the financial support from the Sierra Club. We also thank two anonymous reviewers and our colleagues Francis McMichael and Austin Mitchell for helpful comments. Any opinions, findings, and conclusions or recommendations expressed in this material are those of the authors and do not necessarily reflect the views of the Sierra Club.

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States

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Timothy J. Skone, P.E.

Office of Strategic Energy Analysis and Planning

May 12, 2011

Presented at: Cornell University Lecture Series

U.S. DEPARTMENT OF ENERGY

Overview

1. **Who is NETL?**
2. **What is the role of natural gas in the United States?**
3. **Who uses natural gas in the U.S.?**
4. **Where does natural gas come from?**
5. **What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?**
6. **How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?**
7. **What are the opportunities for reducing GHG emissions?**

<u>Question #1:</u>

Who is NETL?

National Energy Technology Laboratory

MISSION
Advancing energy options
to fuel our economy,
strengthen our security, and
improve our environment

Oregon

Pennsylvania

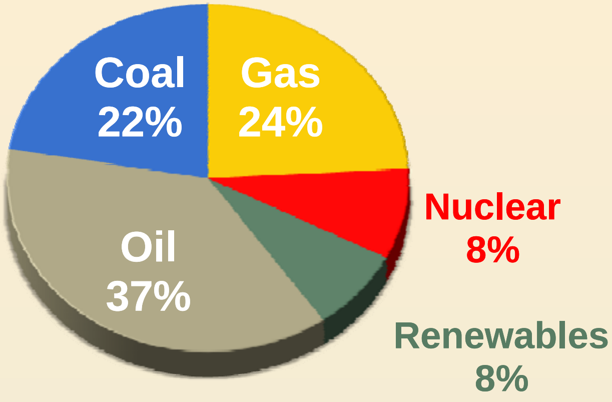
West Virginia

Question #2:

What is the role of natural gas in the United States?

Energy Demand 2008

100 QBtu / Year
84% Fossil Energy



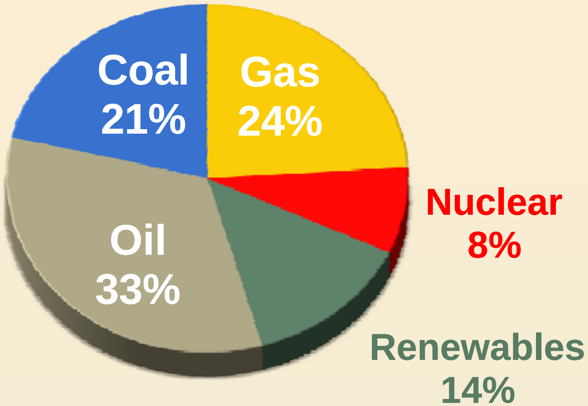
5,838 mmt CO_2

+ 14%

United States

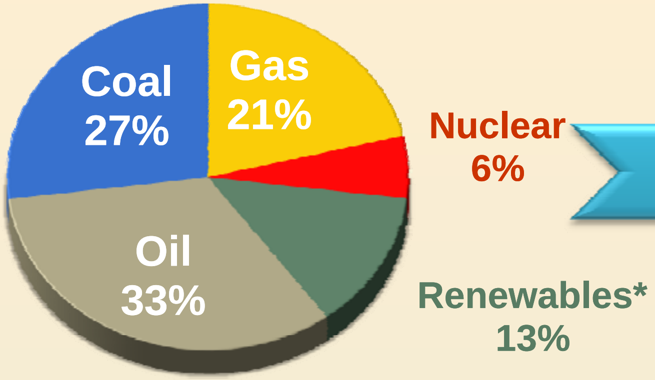
Energy Demand 2035

114 QBtu / Year
78% Fossil Energy



6,311 mmt CO_2

487 QBtu / Year
81% Fossil Energy

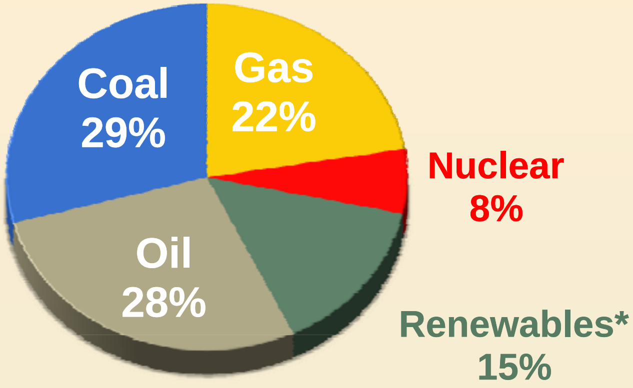


29,259 mmt CO_2

+ 47%

World

716 QBtu / Year
79% Fossil Energy



42,589 mmt CO_2

Sources: U.S. data from EIA, Annual Energy Outlook 2011; World data from IEA, World Energy Outlook 2010, Current Policies Scenario

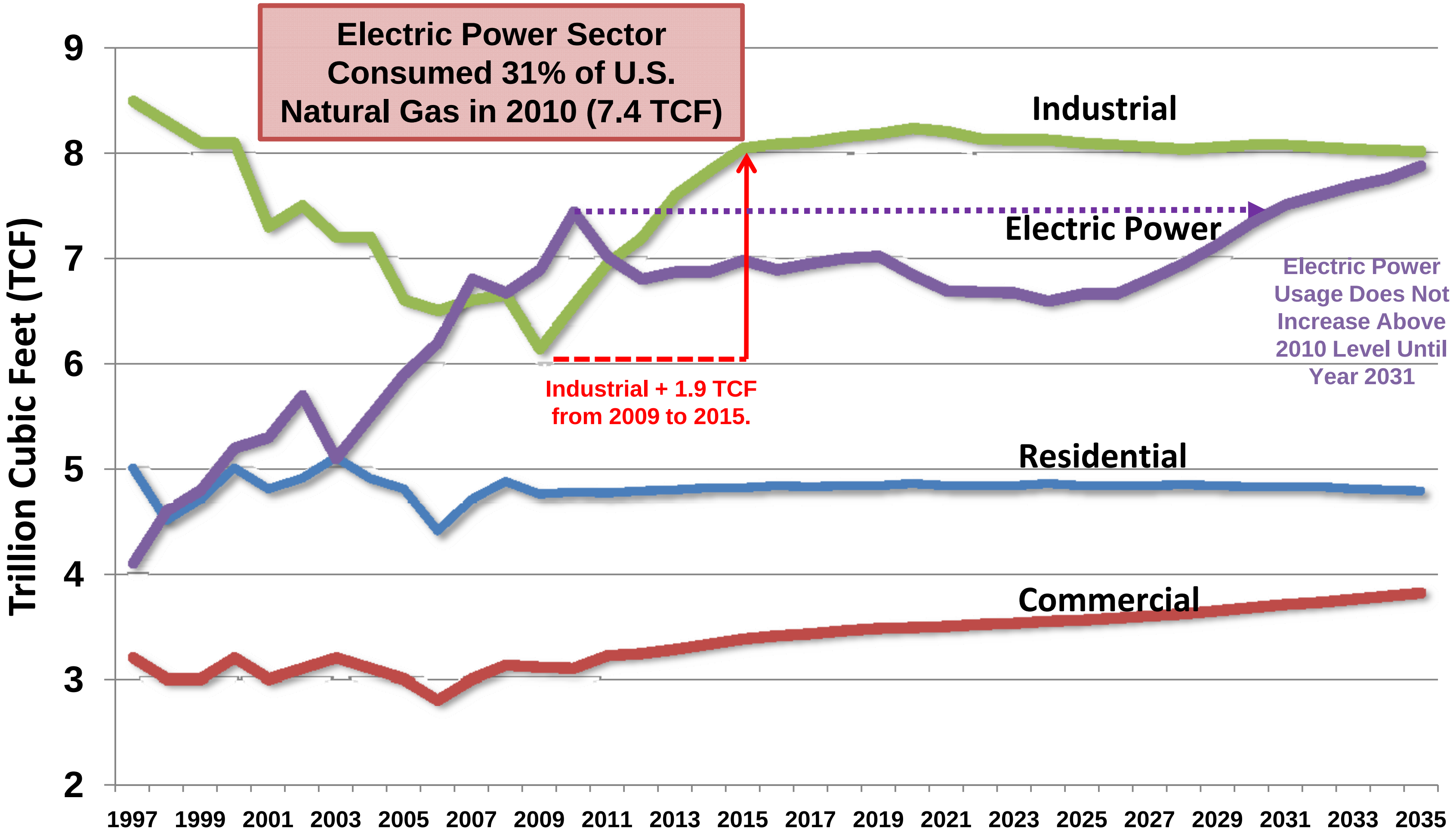
* Primarily traditional biomass, wood, and waste.

Question #3:

Who uses natural gas in the United States?

Domestic Natural Gas Consumption

Sectoral Trends and Projections: 2010 Total Consumption = 23.8 TCF



Electric Power Sector Consumed 31% of U.S. Natural Gas in 2010 (7.4 TCF)

Industrial + 1.9 TCF from 2009 to 2015.

Electric Power Usage Does Not Increase Above 2010 Level Until Year 2031

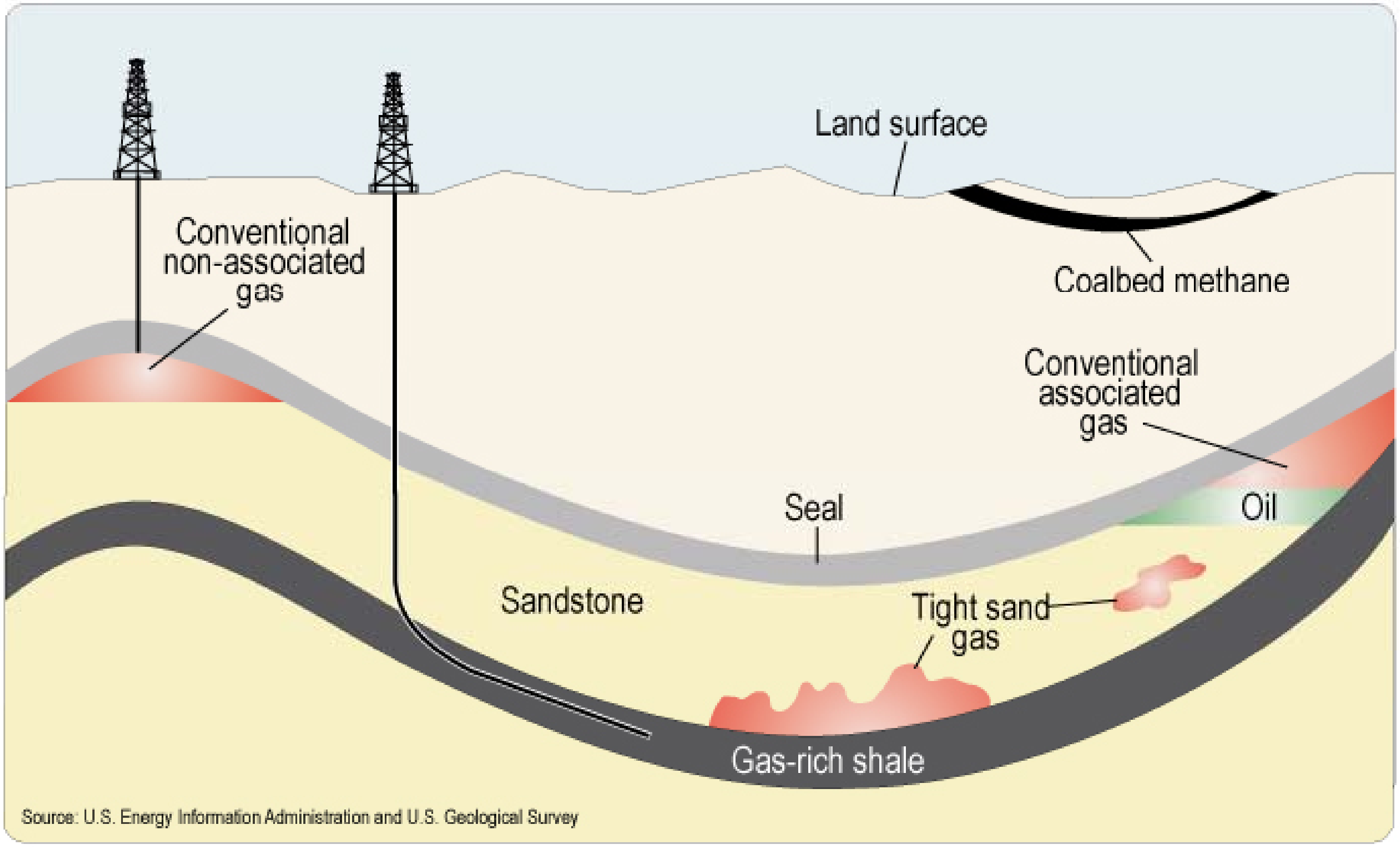
+1.9 TCF Resurgence in Industrial Use of Natural Gas by 2015 Exceeds the Net Incremental Supply; No Increase in Natural Gas Use for Electric Power Sector Until 2031

Source: EIA Annual Energy Review 2009 and Annual Energy Outlook 2011

Question #4:

Where does natural gas come from?

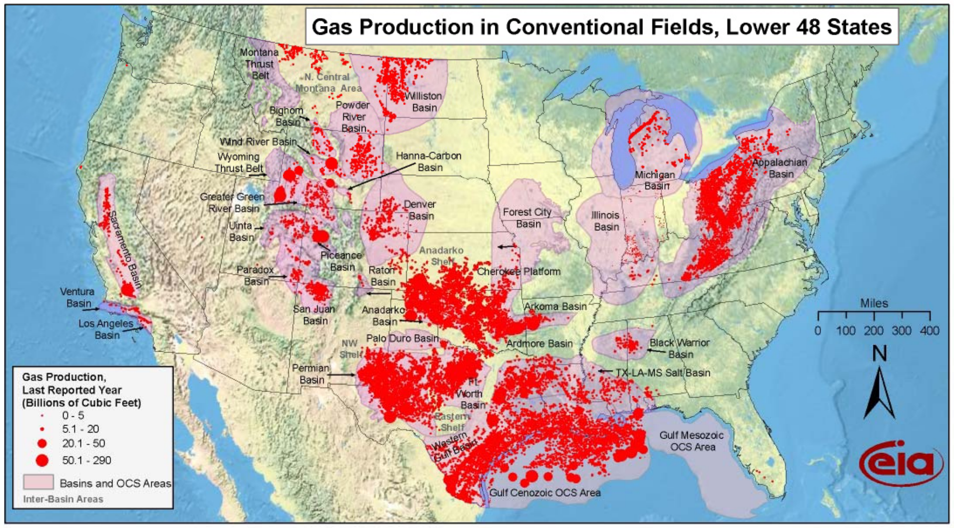
Schematic Geology of Onshore Natural Gas Resources



Source: U.S. Energy Information Administration and U.S. Geological Survey

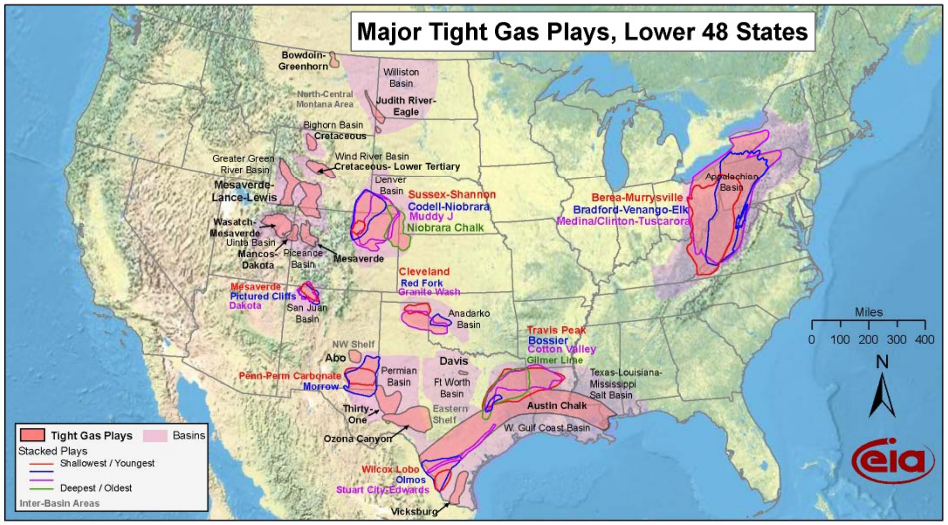
Source: EIA, Today in Energy, February 14, 2011; Modified USGS Figure from Fact Sheet 0113-01; www.eia.doe.gov/todayinenergy/detail.cfm?id=110 Last Accessed May 5, 2011.

EIA Natural Gas Maps



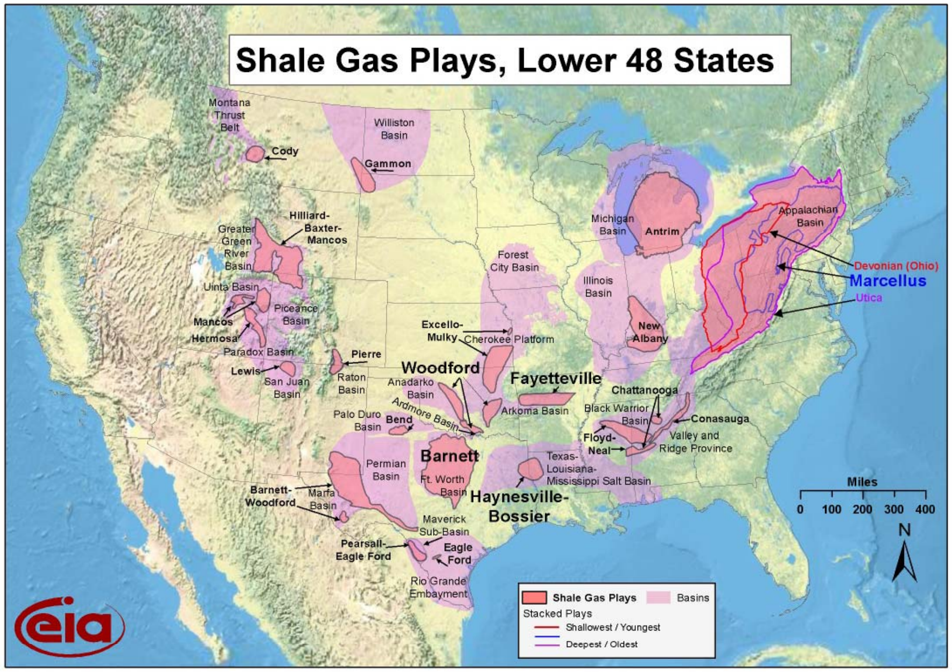
Gas Production in Conventional Fields, Lower 48 States

Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009



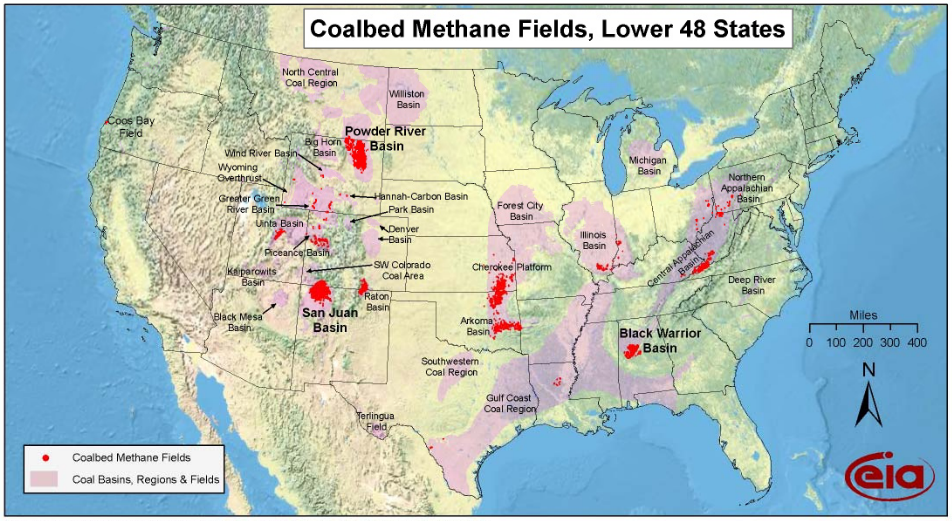
Major Tight Gas Plays, Lower 48 States

Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010



Shale Gas Plays, Lower 48 States

Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010



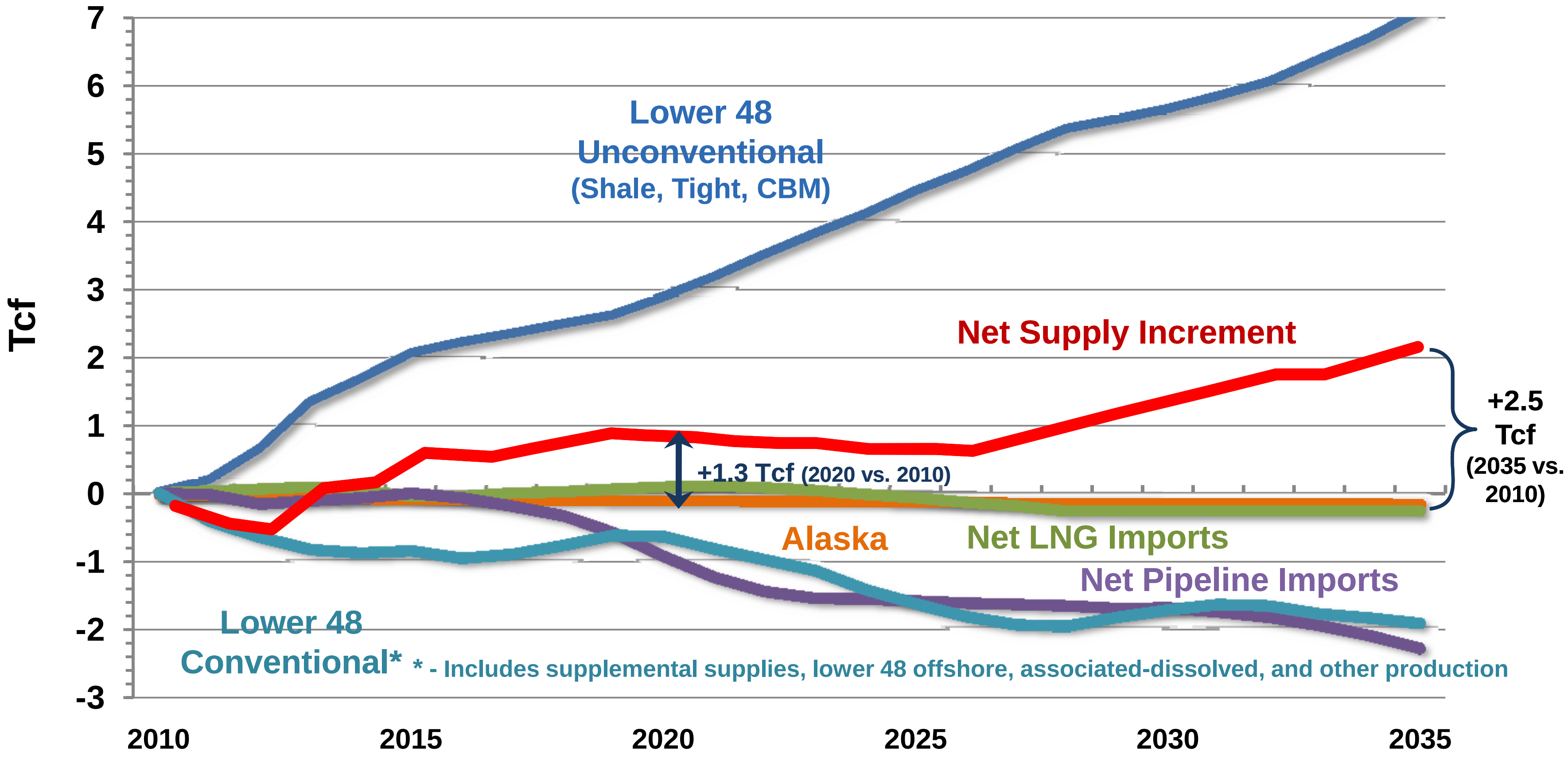
Coalbed Methane Fields, Lower 48 States

Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Source: EIA, Natural Gas Maps, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm Last Accessed May 5, 2011.

Sources of Incremental Natural Gas Supply

(Indexed to 2010)



* - Includes supplemental supplies, lower 48 offshore, associated-dissolved, and other production

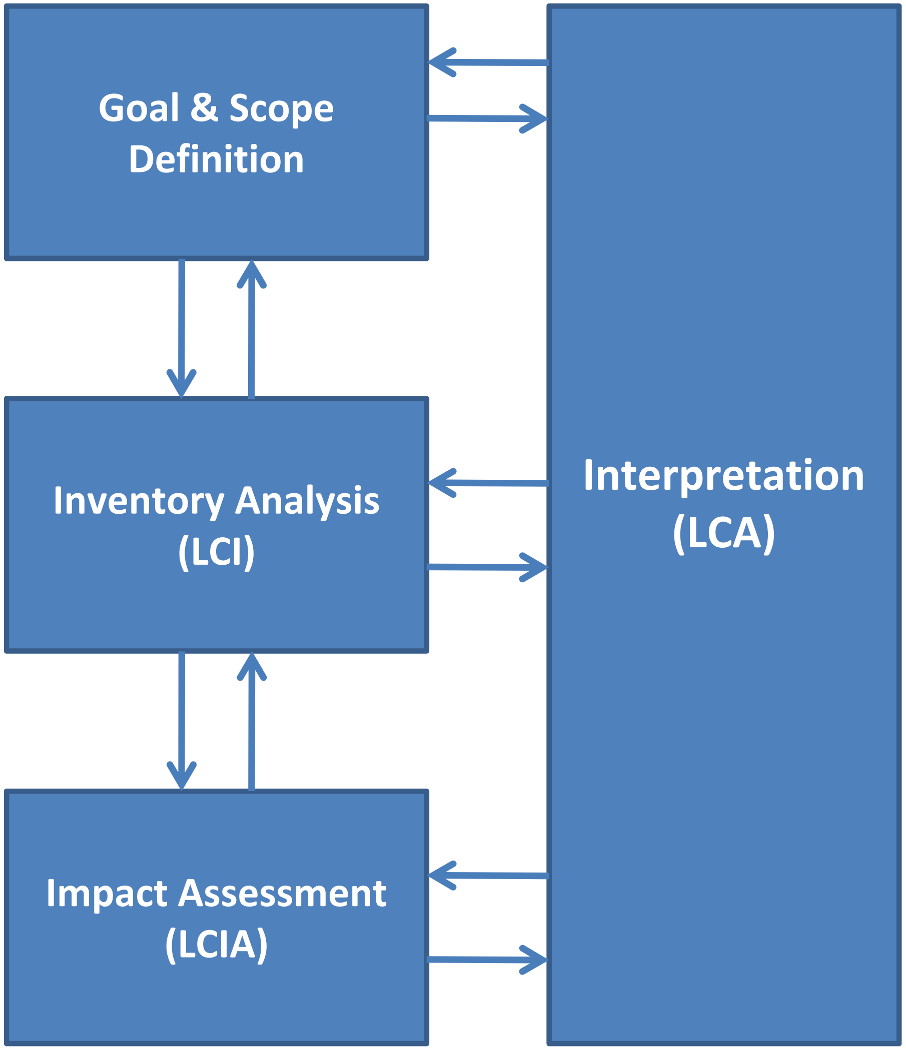
Unconventional Production Growth Offset by Declines in Conventional Production and Net Pipeline Imports; 1.3 Tcf Increment by 2020 Does Not Support Significant Coal Generation Displacement

Source: EIA, Annual Energy Outlook 2011

Question #5:

What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?

Overview: Life Cycle Assessment Approach



Source: ISO 14040:2006, Figure 1 – Stages of an LCA (reproduced)

The Type of LCA Conducted Depends on Answers to these Questions:

1. What Do You Want to Know?

2. How Will You Use the Results?

International Organization for Standardization (ISO) for LCA

- ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principles and Framework
- ISO 14044 Environmental Management – Life Cycle Assessment – Requirements and Guidelines
- ISO/TR 14047:2003 Environmental Management – Life Cycle Impact Assessment – Examples of Applications of ISO 14042
- ISO/TS 14048:2002 Environmental Management – Life Cycle Assessment – Data Documentation Format

Overview: Life Cycle Assessment Approach

The Type of LCA Conducted Depends on Answers to these Questions :

1. What Do You Want to Know?

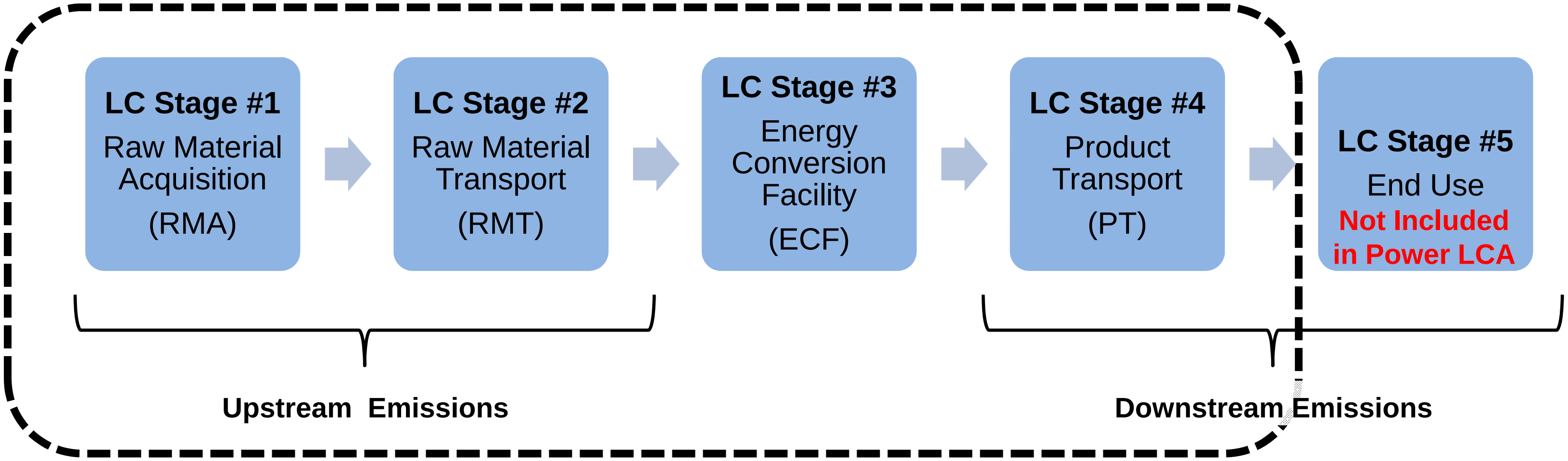
- ☐ **The GHG footprint of natural gas, lower 48 domestic average, extraction, processing, and delivery to a large end-user (e.g., power plant)**
- ☐ **The comparison of natural gas used in a baseload power generation plant to baseload coal-fired power generation on a lbs CO_2e/MWh basis**

2. How Will You Use the Results?

- ☐ **Inform research and development activities to reduce the GHG footprint of both energy feedstock extraction and power production in existing and future operations**

NETL Life Cycle Analysis Approach

- **Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product or service throughout its life cycle, from raw material acquisition to the final disposal**



LC Stage #1
Raw Material Acquisition
(RMA)

LC Stage #2
Raw Material Transport
(RMT)

LC Stage #3
Energy Conversion Facility
(ECF)

LC Stage #4
Product Transport
(PT)

LC Stage #5
End Use
Not Included in Power LCA

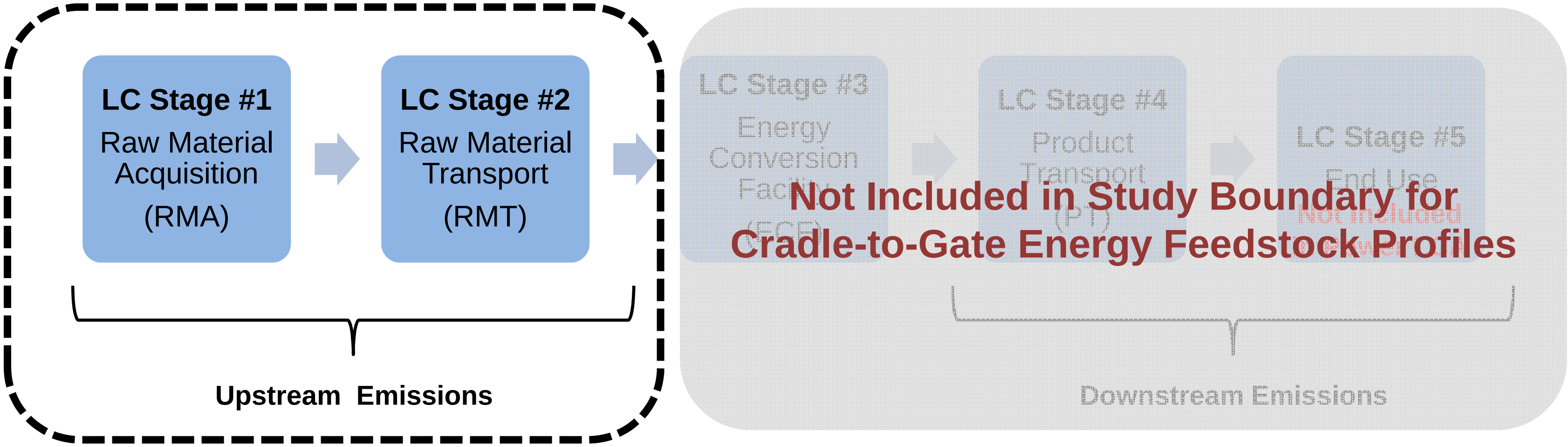
Upstream Emissions

Downstream Emissions

- **The ability to compare different technologies depends on the functional unit (denominator); for power LCA studies:**
  - 1 MWh of electricity delivered to the end user

NETL Life Cycle Analysis Approach for Natural Gas Extraction and Delivery Study

- **The study boundary for “domestic natural gas extraction and delivery to large end-users” is represented by Life Cycle (LC) Stages #1 and #2 only.**



LC Stage #1
Raw Material Acquisition
(RMA)

LC Stage #2
Raw Material Transport
(RMT)

Upstream Emissions

LC Stage #3
Energy Conversion Facility
(ECF)

LC Stage #4
Product Transport
(PT)

LC Stage #5
End Use
Not included

Downstream Emissions

Not Included in Study Boundary for Cradle-to-Gate Energy Feedstock Profiles

- **Functional unit (denominator) for energy feedstock profiles is:**
  - 1 MMBtu of feedstock delivered to end user
    (MMBtu = million British thermal units)

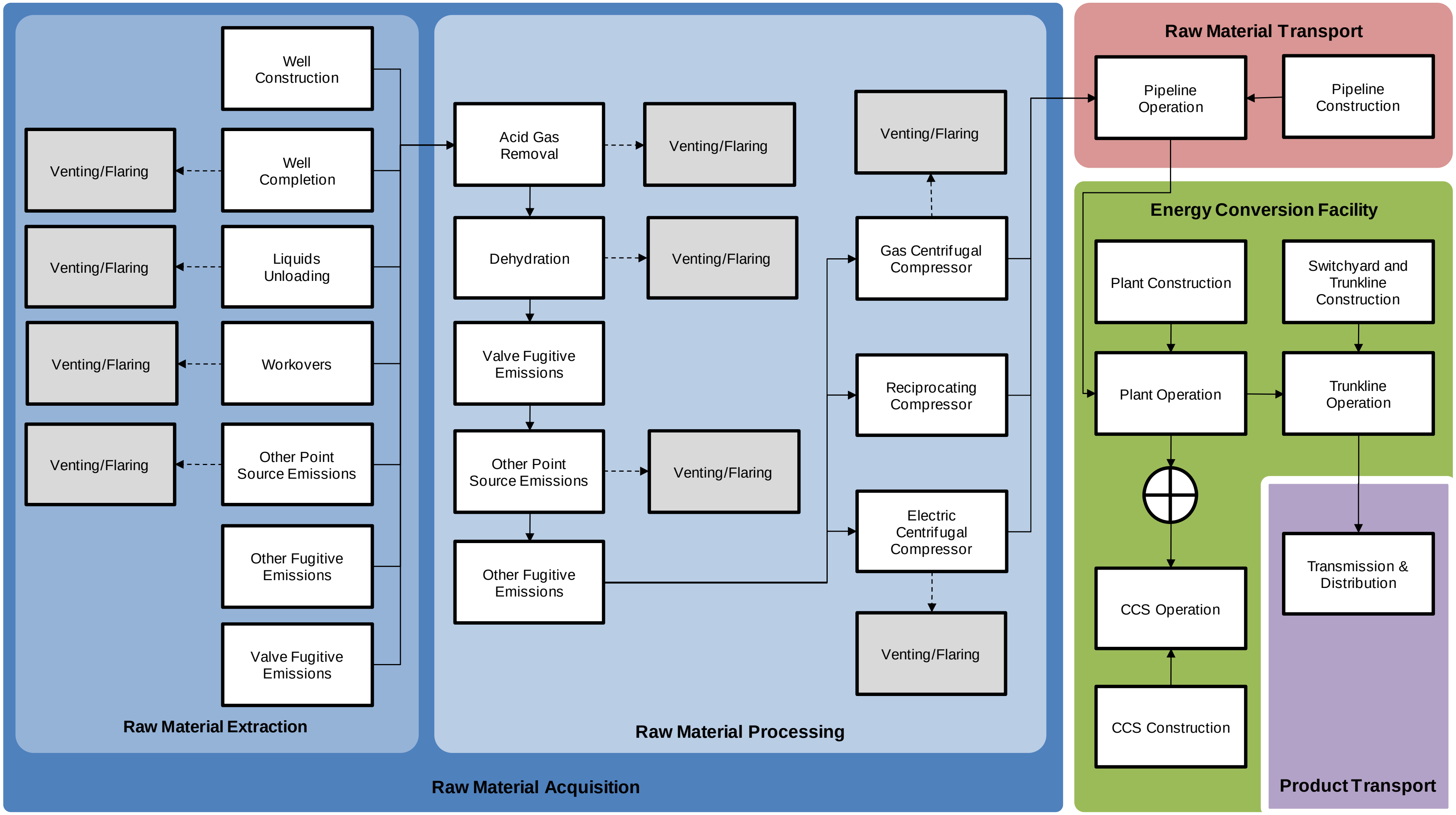
NETL Life Cycle Study Metrics

- **Greenhouse Gases**
  - CO_2, CH_4, N_2O, SF_6
- **Criteria Air Pollutants**
  - NO_X, SO_X, CO, PM10, Pb
- **Air Emissions Species of Interest**
  - Hg, NH_3, radionuclides
- **Solid Waste**
- **Raw Materials**
  - Energy Return on Investment
- **Water Use**
  - Withdrawn water, consumption, water returned to source
  - Water Quality
- **Land Use**
  - Acres transformed, greenhouse gases

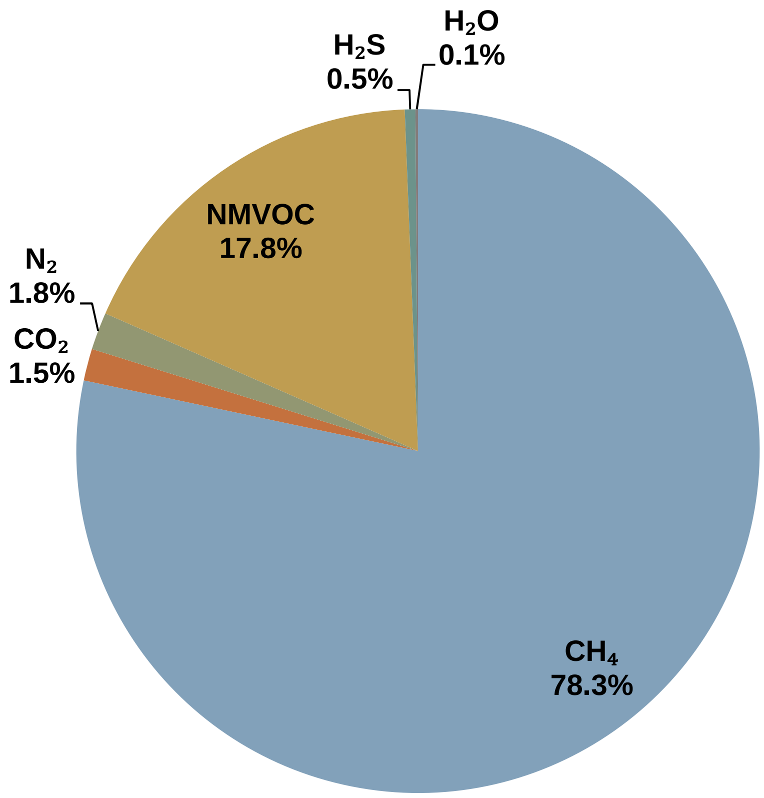
Converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents

CO_2 = 1
CH_4 = 25
N_2O = 298
SF_6 = 22,800

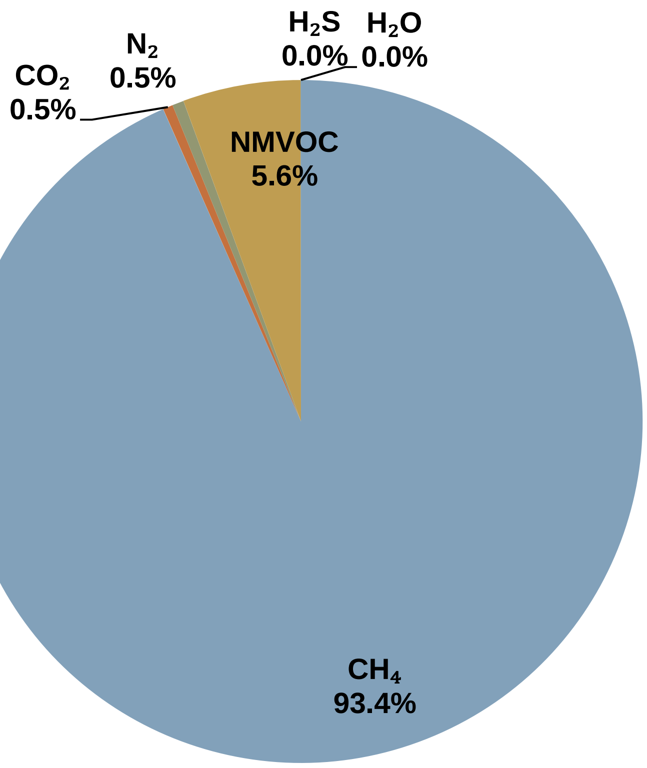
NETL Life Cycle Model for Natural Gas



Natural Gas Composition by Mass



Production Gas



Pipeline Quality Gas

Carbon content (75%) and energy content (1,027 btu/cf) of pipeline quality gas is very similar to raw production gas (within 99% of both values)

Natural Gas Extraction Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
Estimated Ultimate Recovery (EUR), Production Gas	BCF/well	8.6	4.4	67.7	1.2	3.0	0.2
Production Rate (30-yr average)	MCF/day	782	399	6,179	110	274	20
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	MCF/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	MCF/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	MCF/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.043	0.043	0.010	0.043	0.043	0.043

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Acid Gas Removal (AGR) and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%					
Methane Absorbed into Amine Solution	lb CH_4/MCF	0.04					
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/MCF	0.56					
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/MCF	0.21					
NMVOC Absorbed into Amine Solution	lb NMVOC/MCF	6.59					
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%					
Water Removed by Dehydrator Unit	lb H_2O/MCF	0.045					
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/MCF	0.0003					
Pneumatic Devices & Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%					
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05					
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.02					
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.03					

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Natural Gas Transmission Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Emissions on Transmission Infrastructure							
Pipeline Transport Distance (national average)	Miles	450					
Transmission Pipeline Infrastructure, Fugitive	lb CH_4/MCF-Mile	0.0003					
Transmission Pipeline Infrastructure, Fugitive (per 450 miles)	lb CH_4/MCF	0.15					
Natural Gas Compression on Transmission Infrastructure							
Distance Between Compressor Stations	Miles	75					
Compression, Gas-powered Reciprocating	Percent	29%					
Compression, Gas-powered Centrifugal	Percent	64%					
Compression, Electrical Centrifugal	Percent	7%					

Uncertainty Analysis Modeling Parameters

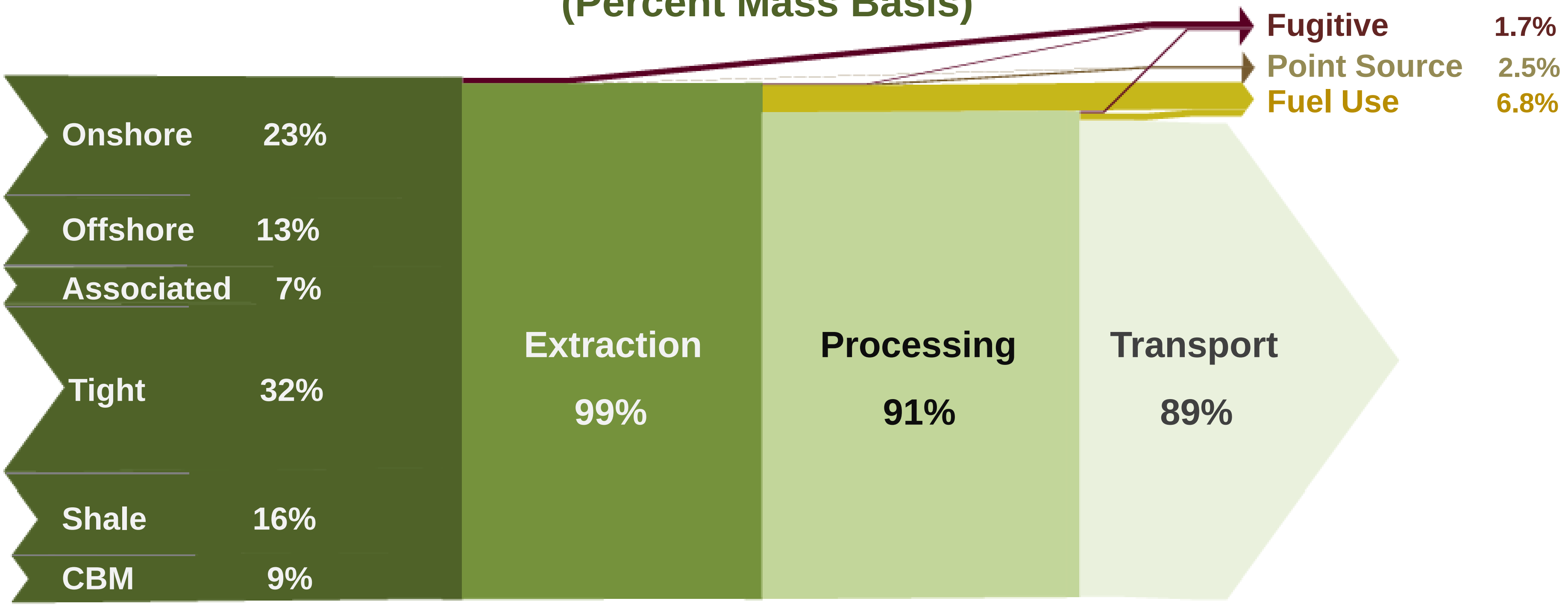
Parameter	Units	Scenario	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Production Rate	MCF/day	Low	403 (-49%)	254 (-36%)	3,140 (-49%)	77 (-30%)	192 (-30%)	14 (-30%)
		Nominal	**782**	**399**	**6,179**	**110**	**274**	**20**
		High	1,545 (+97%)	783 (+96%)	12,284 (+99%)	142 (+30%)	356 (+30%)	26 (+30%)
Flaring Rate at Well	%	Low	41% (-20%)	41% (-20%)	41% (-20%)	12% (-20%)	12% (-20%)	41% (-20%)
		Nominal	**51%**	**51%**	**51%**	**15%**	**15%**	**51%**
		High	61% (+20%)	61% (+20%)	61% (+20%)	18% (+20%)	18% (+20%)	61% (+20%)
Pipeline Distance	miles	Low	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)
		Nominal	**450**	**450**	**450**	**450**	**450**	**450**
		High	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)

Error bars reported are based on setting each of the three parameters above to the values that generate the lowest and highest result.

Note: “Production Rate” and “Flaring Rate at Well” have an inverse relationship on the effect of the study result. For example to generate the lower bound on the uncertainty range both “Production Rate” and “Flaring Rate Well” were set to “High” and “Pipeline Distance” was set to “Low”.

Accounting for Natural Gas from Extraction thru Delivery to a Large End-User

(Percent Mass Basis)

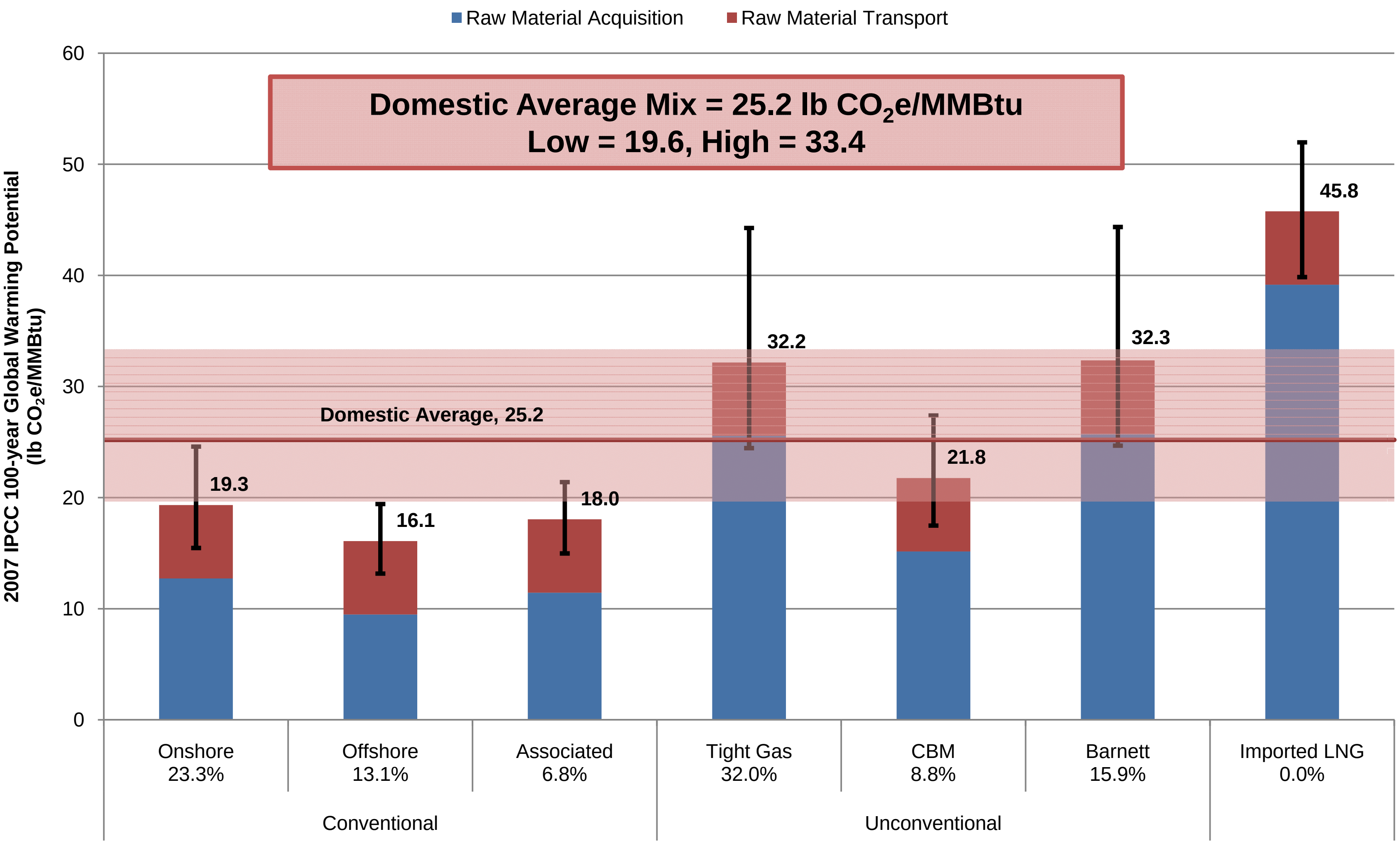


Natural Gas Resource Table	Raw Material Acquisition		Raw Material Transport	Cradle-to-Gate Total:
	Extraction	Processing		
Extracted from Ground	100%	N/A	N/A	100%
Fugitive Losses	1.1%	0.2%	0.4%	1.7%
Point Source Losses (Vented or Flared)	0.1%	2.4%	0.0%	2.5%
Fuel Use	0.0%	5.3%	1.6%	6.8%
Delivered to End User	N/A	N/A	89.0%	89.0%

11% of Natural Gas Extracted from the Earth is Consumed for Fuel Use, Flared, or Emitted to the Atmosphere (point source or fugitive)

Of this, 62% is Used to Power Equipment

Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

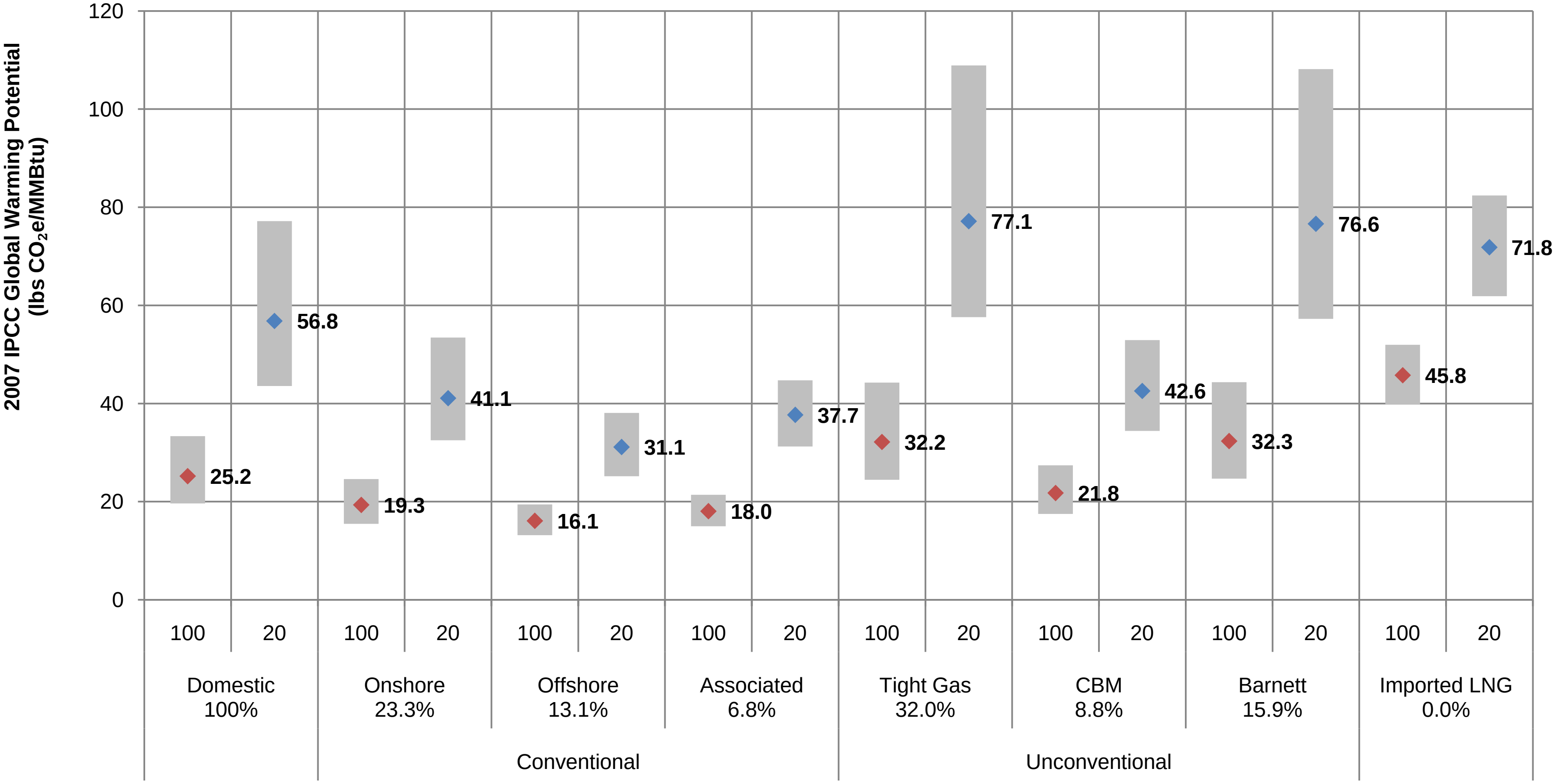


Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

<u>Comparison of 2007 IPCC GWP Time Horizons:</u>

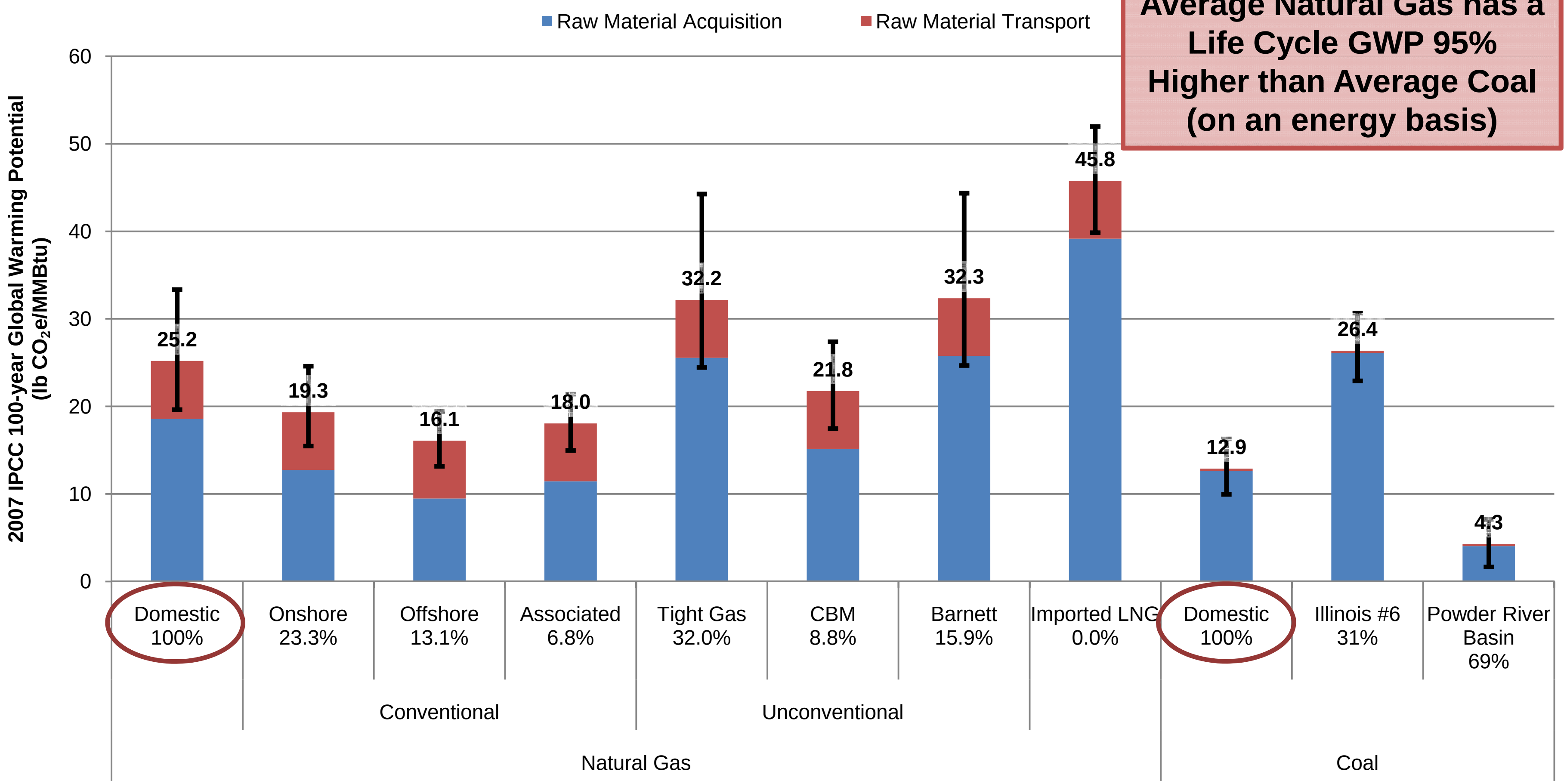
100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289



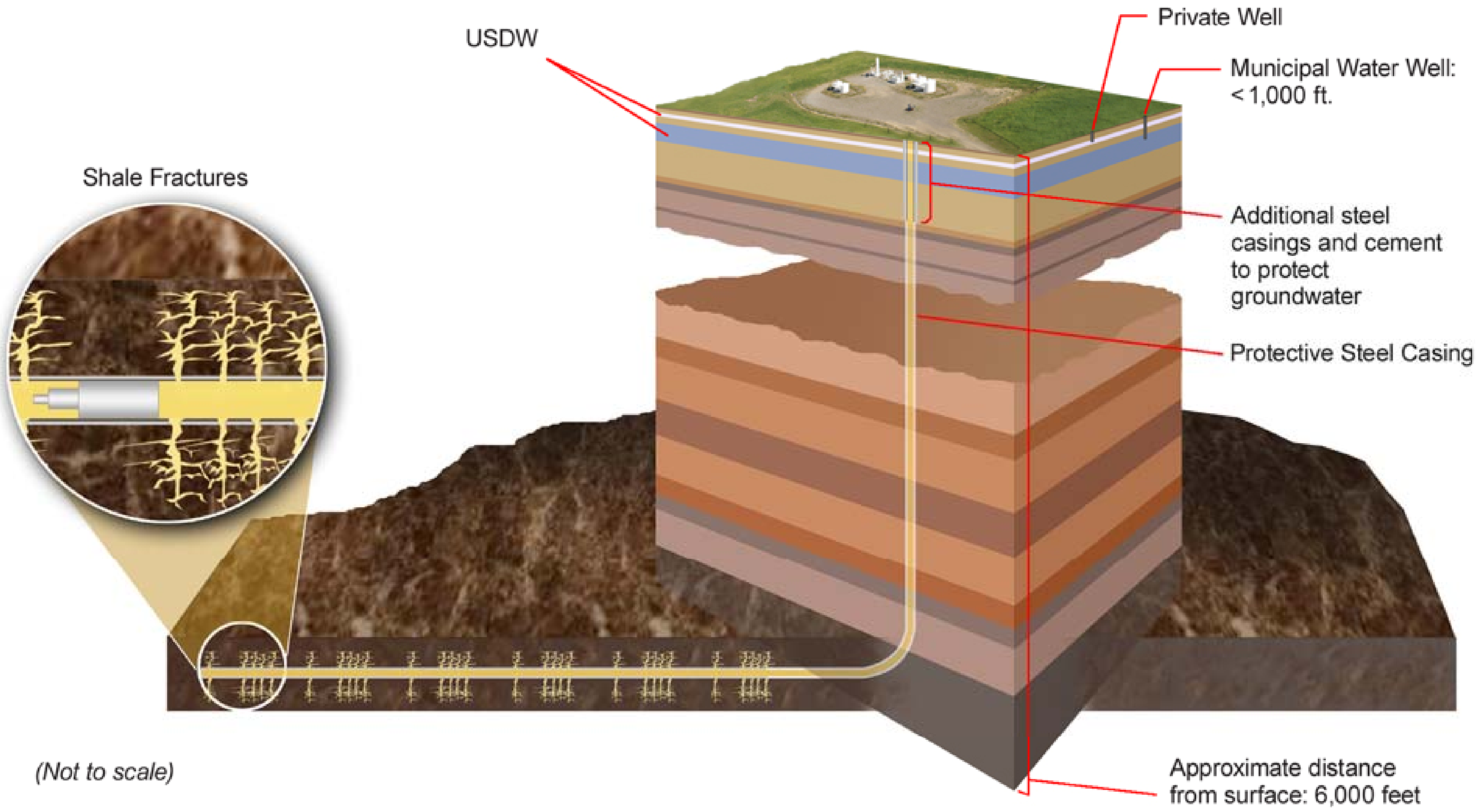
Life Cycle GHG Results for “Average” Natural Gas Extraction and Delivery to a Large End-User

Comparison of Natural Gas and Coal Energy Feedstock GHG Profiles



Average Natural Gas has a Life Cycle GWP 95% Higher than Average Coal (on an energy basis)

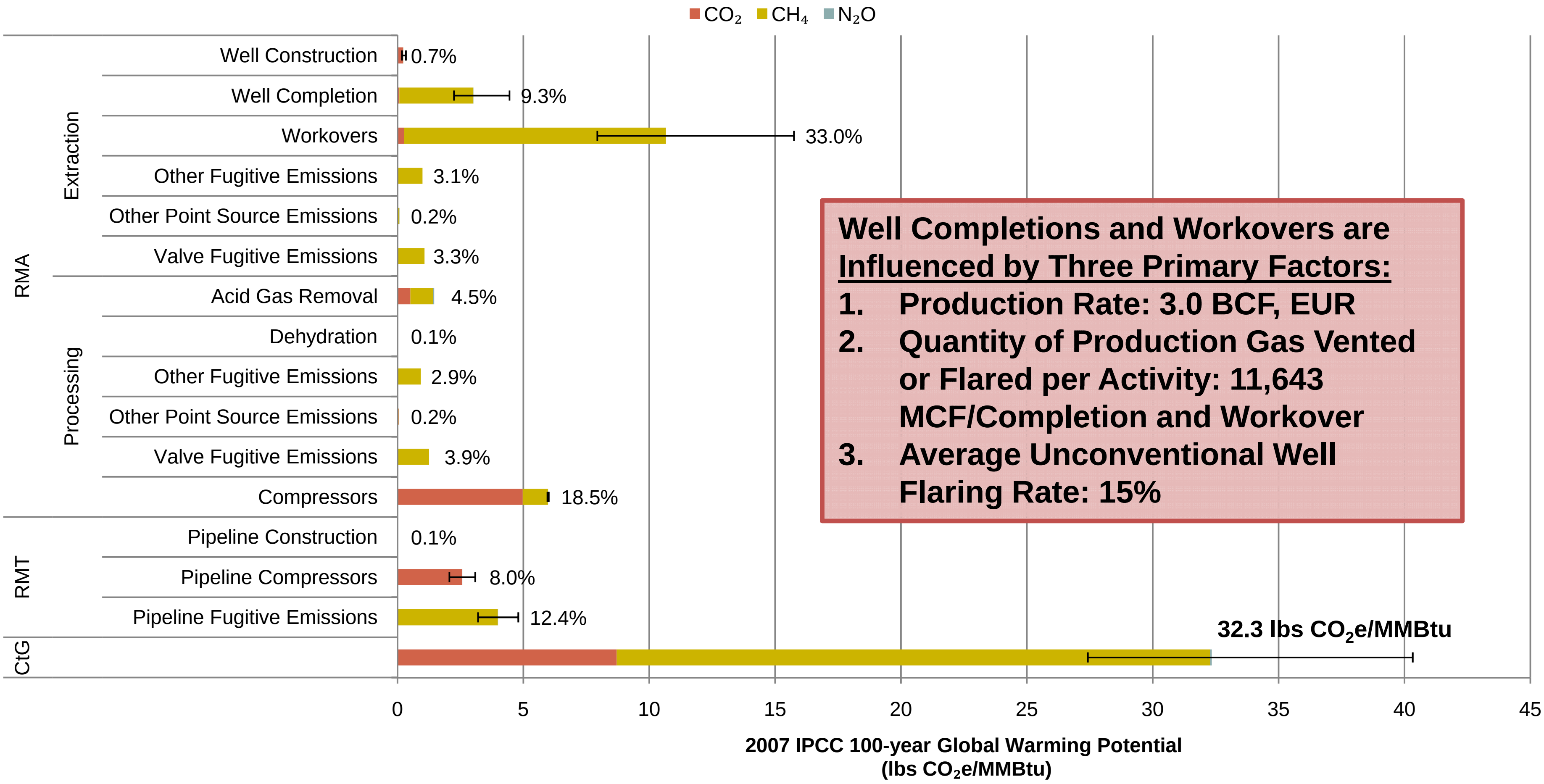
A Deeper Look at Unconventional Natural Gas Extraction via Horizontal Well, Hydraulic Fracturing (*the Barnett Shale Model*)



Source: NETL, *Shale Gas: Applying Technology to Solve America's Energy Challenge*, January 2011

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

GWP Result: IPCC 2007, 100-yr (lb CO_2e/MMBtu)



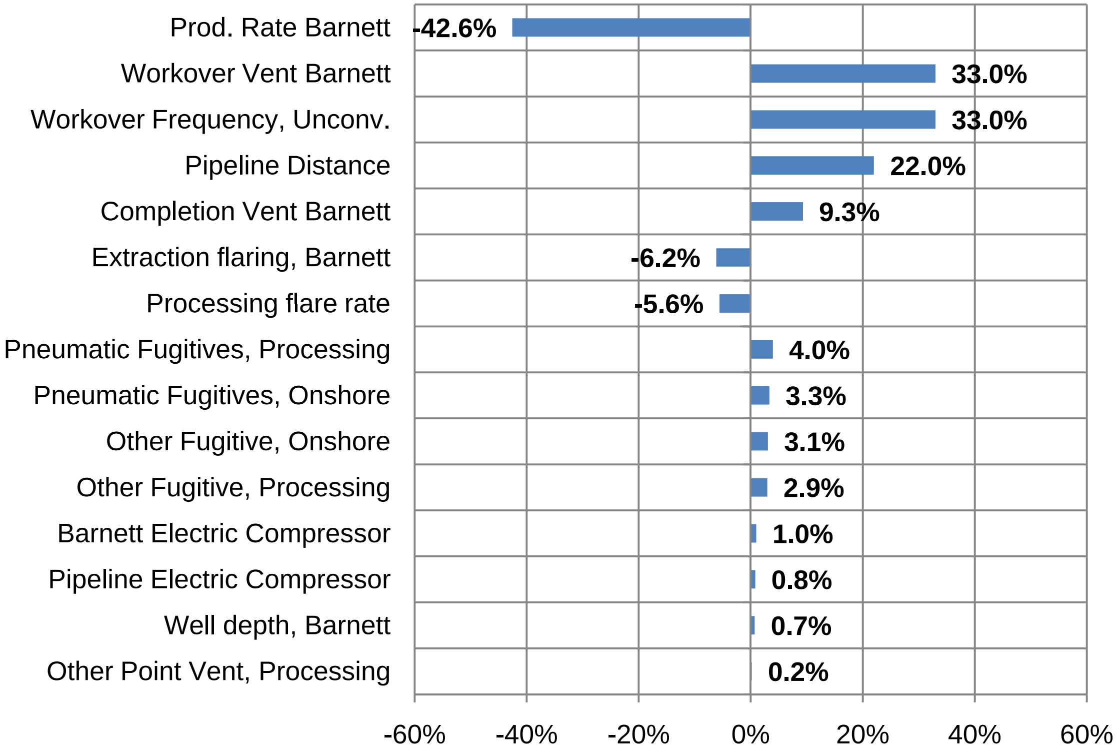
Well Completions and Workovers are <u>Influenced by Three Primary Factors:</u>

1. **Production Rate: 3.0 BCF, EUR**
2. **Quantity of Production Gas Vented or Flared per Activity: 11,643 MCF/Completion and Workover**
3. **Average Unconventional Well Flaring Rate: 15%**

NETL Upstream Natural Gas Profile:

Barnett Shale: Horizontal Well, Hydraulic Fracturing

Sensitivity Analysis



Default Value	Units
11,508	lb/day
489,023	lb/episode
0.118	episodes/yr
450	miles
489,023	lb/episode
15.0	%
100	%
0.001480	lb fugitives/lb processed gas
0.001210	lb fugitives/lb extracted gas
0.001119	lb fugitives/lb extracted gas
0.001089	lb fugitives/lb processed gas
25	%
7	%
13,000	feet
0.0003940	lb fugitives/lb processed gas

“0%” = 32.3 lb CO_2e/MMBtu Delivered; IPCC 2007, 100-yr Time Horizon

Example: A 1% increase in production rate from 11,508 lb/day to 11,623 lb/day results in a 0.426% decrease in cradle-to-gate GWP, from 32.3 to 32.2 lbs CO_2e/MMBtu

Question #6:

How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?

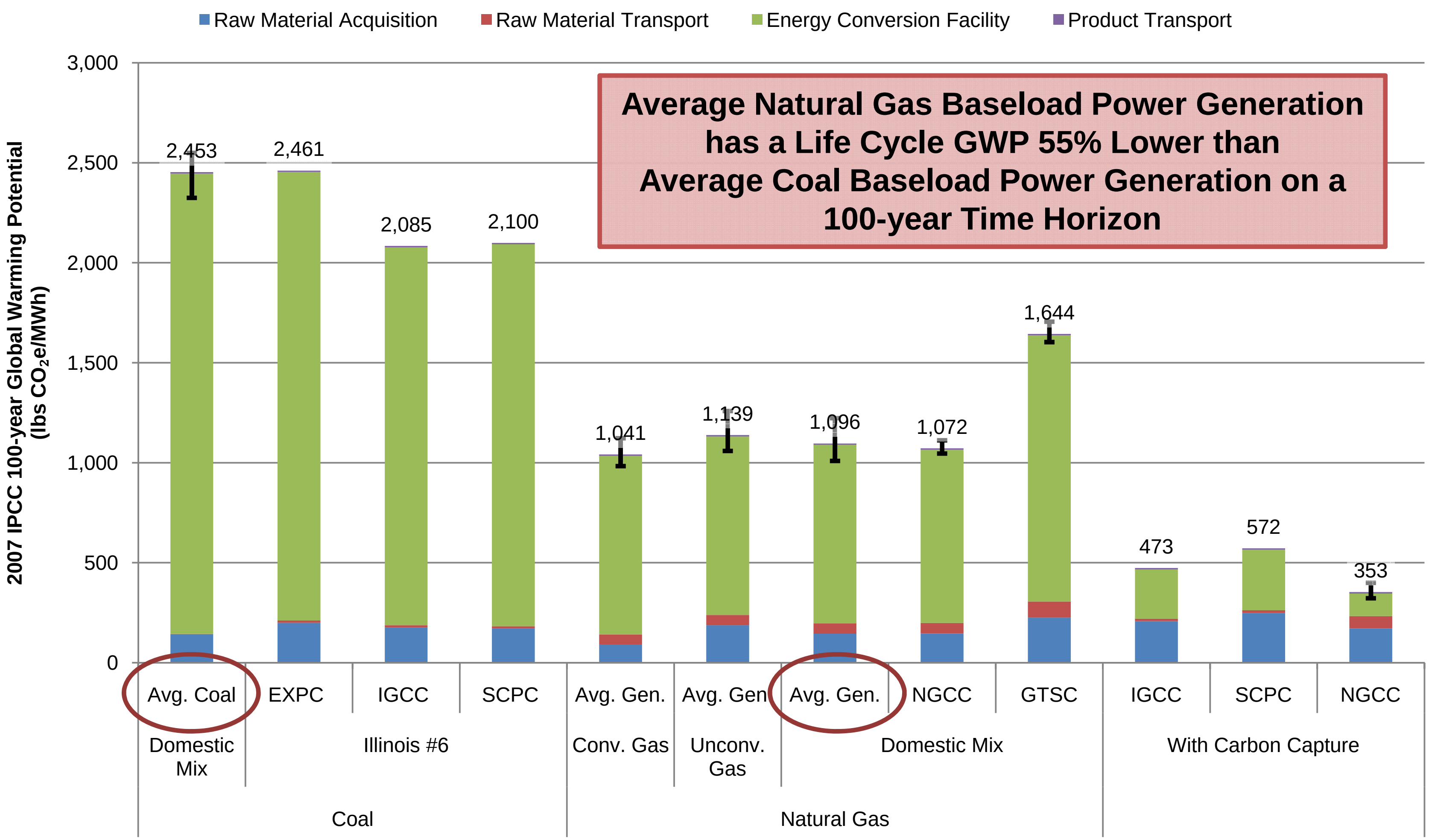
Power Technology Modeling Properties

Plant Type	Plant Type Abbreviation	Fuel Type	Capacity (MW)	Capacity Factor	Net Plant HHV Efficiency
2009 Average Coal Fired Power Plant[a]	Avg. Coal	Domestic Average	Not Calculated	Not Calculated	33.0%
Existing Pulverized Coal Plant	EXPC	Illinois No. 6	434	85%	35.0%
Integrated Gasification Combined Cycle Plant	IGCC	Illinois No. 6	622	80%	39.0%
Super Critical Pulverized Coal Plant	SCPC	Illinois No. 6	550	85%	36.8%
2009 Average Baseload (> 40 MW) Natural Gas Plant[a]	Avg. Gen.	Domestic Average	Not Calculated	Not Calculated	47.1%
Natural Gas Combined Cycle Plant	NGCC	Domestic Average	555	85%	50.2%
Gas Turbine Simple Cycle	GTSC	Domestic Average	360	85%	32.6%
Integrated Gasification Combined Cycle Plant with 90% Carbon Capture	IGCC/CCS	Illinois No. 6	543	80%	32.6%
Super Critical Pulverized Coal Plant with 90% Carbon Capture	SCPC/CCS	Illinois No. 6	550	85%	26.2%
Natural Gas Combined Cycle Plant with 90% Carbon Capture	NGCC/CCS	Domestic Average	474	85%	42.8%

[a] **Net plant higher heating value (HHV) efficiency reported is based on the weighted mean of the 2007 fleet as reported by U.S. EPA, eGrid (2010).**

Comparison of Power Generation Technology Life Cycle GHG Footprints

Raw Material Acquisition thru Delivery to End Customer (lb CO_2e/MWh)



Average Natural Gas Baseload Power Generation has a Life Cycle GWP 55% Lower than Average Coal Baseload Power Generation on a 100-year Time Horizon

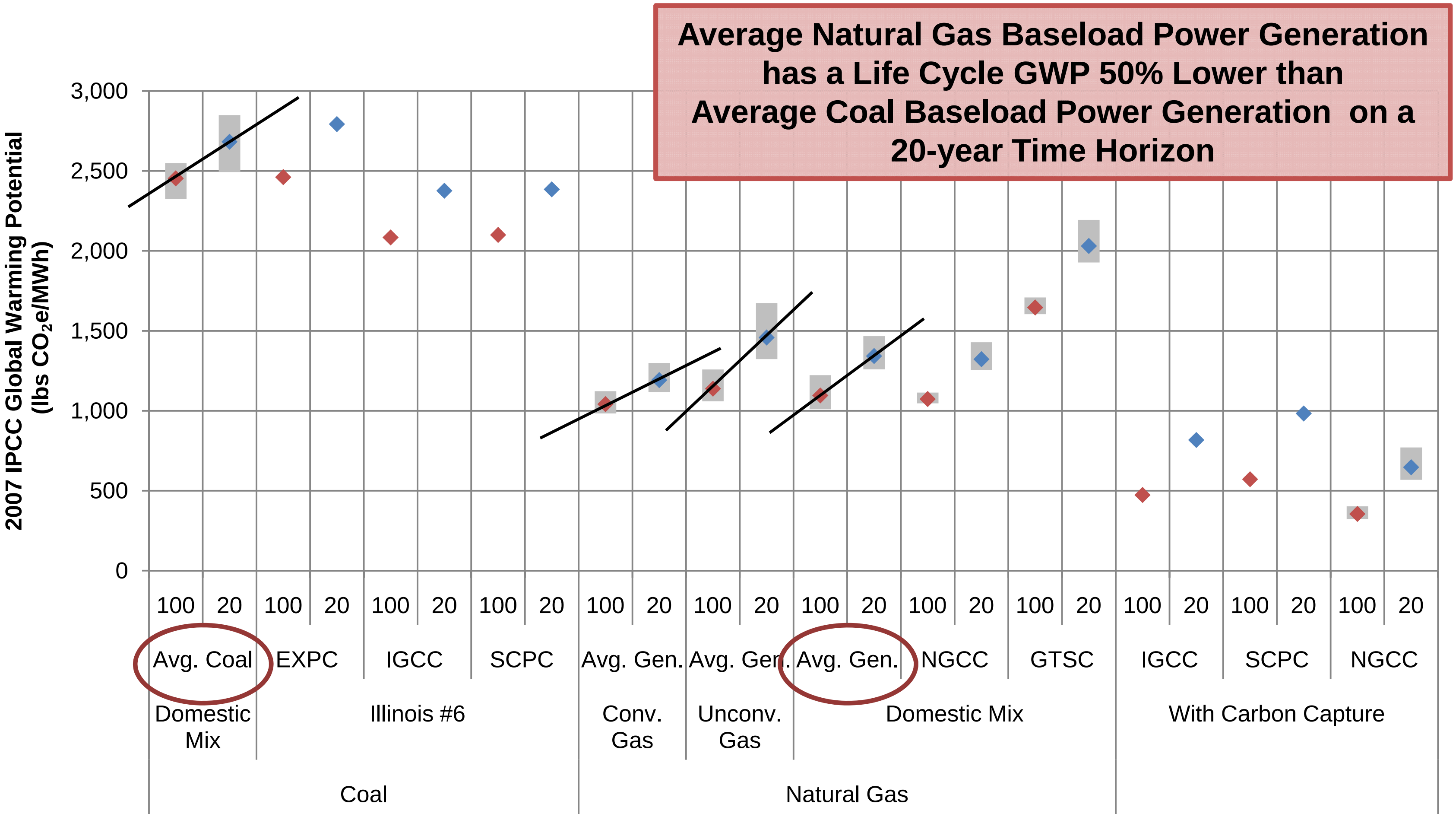
Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Comparison of Power Generation Technology Life Cycle GHG Footprints (lbs CO_2e/MWh)

Comparison of 2007 IPCC GWP Time Horizons:

100-year Time Horizon: $CO_2 = 1$, $CH_4 = 25$, $N_2O = 298$

20-year Time Horizon: $CO_2 = 1$, $CH_4 = 72$, $N_2O = 289$



Average Natural Gas Baseload Power Generation has a Life Cycle GWP 50% Lower than Average Coal Baseload Power Generation on a 20-year Time Horizon

Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Study Data Limitations

- **Data Uncertainty**
  - Episodic emission factors
  - Formation-specific production rates
  - Flaring rates (extraction and processing)
  - Natural gas pipeline transport distance

- **Data Availability**
  - Formation-specific gas compositions (including CH_4, H_2S, NMVOC, and water)
  - Effectiveness of green completions and workovers
  - Fugitive emissions from around wellheads (between the well casing and the ground)
  - GHG emissions from the production of fracing fluid
  - Direct and indirect GHG emissions from land use from access roads and well pads
  - Gas exploration
  - Treatment of fracing fluid
  - Split between venting and fugitive emissions from pipeline transport

Question #7:

What are the opportunities for reducing GHG emissions?

Technology Opportunities

- **Opportunities for Reducing the GHG Footprint of Natural Gas Extraction and Delivery**
  - Reduce emissions from unconventional gas well completions and workovers
    - Better data is needed to properly characterize this opportunity based on basin type, drilling method, and production rate
  - Improve compressor fuel efficiency
  - Reduce pipeline fugitive emissions thru technology and best management practices (collaborative initiatives)

- **Opportunities for Reducing the GHG Footprint of Natural Gas and Coal-fired Power Generation**
  - Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir (CO_2-EOR)
  - Improve existing power plant efficiency
  - Invest in advanced power research, development, and demonstration

All Opportunities Need to Be Evaluated on a Sustainable Energy Basis: Environmental Performance, Economic Performance, and Social Performance (e.g., energy reliability and security)

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- Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant
- Life Cycle Analysis: Power Studies Compilation Report

Analysis complete, report in draft form:

- Life Cycle GHG Analysis of Natural Gas Extraction and Delivery
- Life Cycle Assessment of Wind Power with GTSC Backup
- Life Cycle Assessment of Nuclear Power

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- An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin (Report)
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