

Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990-2020

**Center for Climate Strategies
February 2007**

Principal Authors: Stephen Roe, Randy Strait Alison Bailie, Holly Lindquist, Alison Jamison



[This page intentionally left blank.]

Executive Summary

The Center for Climate Strategies (CCS) prepared this report for the Alaska Department of Environment Conservation (ADEC) under an agreement with the Western Governors' Association. The report contains an inventory and forecast of the State's greenhouse gas (GHG) emissions from 1990 to 2020.

Alaska's anthropogenic GHG emissions and sinks (carbon storage) were estimated for the period from 1990 to 2020. Historical GHG emission estimates (1990 through 2005) were developed using a set of generally-accepted principles and guidelines for state GHG emission estimates, with adjustments by CCS to provide Alaska-specific data and inputs when it was possible to do so. The initial reference case emission projections (2006-2020) are based on a compilation of various existing projections of electricity generation, fuel use, and other GHG-emitting activities, along with a set of transparent assumptions.

Table ES-1 provides a summary of historical (1990, 2000 and 2005) and reference case projection (2010 and 2020) GHG emissions for Alaska. Activities in Alaska accounted for approximately 52.4 million metric tons (MMt) of *gross*¹ carbon dioxide equivalent (CO₂e) emissions in 2005, an amount equal to about 0.7% of total U.S. gross GHG emissions. Alaska's gross GHG emissions grew at about the same rate as those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Alaska's gross GHG emissions increased 12% from 1990 to 2000, while national emissions rose by 14% during this period.

Figure ES-1 illustrates the State's emissions per capita and per unit of economic output. On a per capita basis, Alaskans emit about 82 metric tons (Mt) of CO₂e annually, higher than the national average of 25 MtCO₂e/yr. The higher per capita emission rates in Alaska are driven by emissions from the fossil fuel industry and transportation sectors, which are much higher than the national average. As in the nation as a whole, per capita emissions in Alaska have changed relatively little, while economic growth exceeded emissions growth throughout the 1990-2005 period (leading to declining estimates of GHG emissions per unit of state product). During the 1990s, emissions per unit of gross product dropped by 40% nationally, and by 23% in Alaska.

The principal source of Alaska's GHG emissions is residential, commercial, and industrial (RCI) fuel use, accounting for 49% of total State gross GHG emissions in 2005. Nearly 85% of the RCI fuel use sector emissions are contributed by the industrial fuel use subsector. The next largest contributor to total gross GHG emissions is the transportation sector, which accounted for 38% of the total State gross GHG emissions.

As illustrated in Figure ES-2 and shown numerically in Table ES-1, under the reference case projections, Alaska's gross GHG emissions continue to grow, and are projected to climb to 61.4 MMtCO₂e per year by 2020, 42% above 1990 levels. As shown in Figure ES-3, emissions associated with RCI fuel use are projected to be the largest contributor to future emissions growth, followed by emissions from the transportation sector. Estimates of carbon dioxide

¹ Excluding GHG emissions removed (e.g., CO₂ sequestered) in forestry and other land uses.

sequestered in Alaska's managed forests are -1.4 MMtCO₂/yr ("managed forests" consist of the coastal maritime forests in Alaska; see Appendix H).

Emissions of aerosols, particularly "black carbon" (BC) from fossil fuel combustion, could have significant climate impacts through their effects on radiative forcing. Estimates of these aerosol emissions on a CO₂e basis were developed for Alaska based on 2002 data and 2018 projected data from the Western Regional Air Partnership (WRAP). Estimated BC emissions for the year 2002 were a total of 3.0 MMtCO₂e, which is the mid-point of a range of estimated emissions (1.9 – 4.0 MMtCO₂e). Based on an assessment of the primary contributors, it is estimated that BC emissions will decrease by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors. Details of this analysis are presented in Appendix I to this report. These estimates are not incorporated into the totals shown in Table ES-1 below because a global warming potential for BC has not yet been assigned by the Intergovernmental Panel on Climate Change (IPCC).

Some data gaps exist in this analysis, particularly for the reference case projections. Key tasks for future GHG inventory work in Alaska include review and revision of key emissions drivers. These include electricity, fossil fuel production, and transportation fuel use growth rates and future electricity generation source mix, which will be major determinants of Alaska's future GHG emissions. In addition, emission estimates from sources that have not yet been estimated should be investigated. These include emissions of associated CO₂ in the oil and gas industry. Details on recommendations for future work are provided in the appendix for each sector.

Table ES-1. Alaska Historical and Reference Case GHG Emissions, by Sector^a

(Million Metric Tons CO ₂ e)	1990	2000	2005	2010	2020	Explanatory Notes for Projections
Electricity Production	2.6	3.1	3.2	3.6	3.7	
Coal	0.4	0.8	0.6	0.6	0.6	See electric sector assumptions in appendix
Natural Gas	1.9	1.9	2.1	2.1	2.1	
Oil	0.3	0.5	0.6	0.9	1.0	
Net Exported Electricity	0	0	0	0	0	
Residential/Commercial	3.8	4.3	3.9	3.9	4.1	
Coal	0.8	0.8	0.7	0.7	0.7	Based on USDOE regional projections
Natural Gas	1.8	2.2	1.9	1.9	2.1	Based on USDOE regional projections
Oil	1.2	1.3	1.3	1.3	1.3	Based on USDOE regional projections
Wood (CH ₄ and N ₂ O)	0.02	0.01	0.02	0.02	0.02	Based on USDOE regional projections
Industrial (Non-Fossil Prod.)	15.7	19.6	21.6	23.5	28.5	
Coal	0.00	0.001	0.001	0.001	0.001	Based on USDOE regional projections
Natural Gas	13.2	17.3	18.5	19.9	24.4	Based on USDOE regional projections
Oil	2.4	2.4	3.1	3.6	4.1	Based on USDOE regional projections
Wood (CH ₄ and N ₂ O)	0.01	0.00	0.00	0.00	0.00	Based on USDOE regional projections
Transportation	15.6	17.1	19.4	19.8	20.4	
Aviation	7.2	10.6	12.9	12.9	12.5	FAA aircraft operations forecasts DEC commercial marine inventory growth factors
Marine Vessels	4.4	2.4	2.4	2.6	3.0	
Onroad Vehicles	3.4	3.7	3.6	3.9	4.4	WRAP inventory VMT projections Historical trends and USDOE regional projections
Rail and Other	0.6	0.4	0.4	0.4	0.5	
Fossil Fuel Industry	4.9	3.2	3.0	2.9	2.1	
Natural Gas Industry	0.2	0.4	0.5	0.4	0.4	Historical trends and DNR natural gas production forecasts
Oil Industry	4.7	2.8	2.5	2.4	1.7	Historical trends and DNR oil production forecasts
Coal Mining (Methane)	0.01	0.01	0.01	0.01	0.01	Historical trend
Industrial Processes	0.05	0.2	0.3	0.5	0.7	
Limestone and Dolomite Use	0.000	0.000	0.01	0.01	0.01	Alaska manufacturing employment growth National projections for 2004-2009 (USGS)
Soda Ash	0.01	0.01	0.01	0.01	0.01	EPA 2004 ODS cost study report Based on national projections (USEPA)
ODS Substitutes	0.001	0.2	0.3	0.4	0.7	
SF ₆ from Electric Utilities	0.04	0.03	0.02	0.02	0.01	
Waste Management	0.6	0.9	1.0	1.2	1.7	
Solid Waste Management	0.6	0.8	1.0	1.1	1.6	Projected based on 1995-2005 trend
Wastewater Management	0.1	0.1	0.1	0.1	0.1	Projected based on population
Agriculture	0.05	0.05	0.05	0.06	0.07	
Manure Management	0.001	0.002	0.004	0.01	0.01	USDA livestock projections
Enteric Fermentation	0.01	0.02	0.02	0.02	0.03	USDA livestock projections
Agricultural Soils	0.04	0.04	0.03	0.03	0.03	Projected based on historical trend
Total Gross Emissions	43.3	48.6	52.4	55.4	61.4	
<i>increase relative to 1990</i>		<i>12%</i>	<i>21%</i>	<i>28%</i>	<i>42%</i>	
Forestry and Land Use	-0.3	-1.4	-1.4	-1.4	-1.4	Projections held constant at 2000 level.
Net Emissions (incl. forestry*)	43.0	47.2	51.0	54.0	60.0	
<i>increase relative to 1990</i>		<i>10%</i>	<i>19%</i>	<i>33%</i>	<i>39%</i>	

^a Totals may not equal exact sum of subtotals shown in this table due to independent rounding. NA = not available.

Figure ES-1. Historical Alaska and U.S. GHG Emissions, Per Capita and Per Unit Gross Product

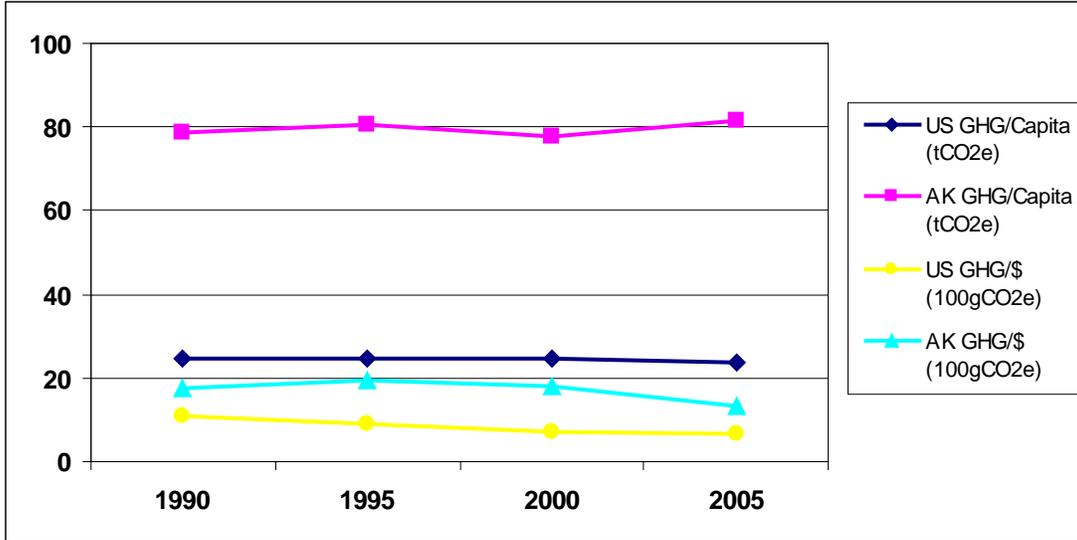
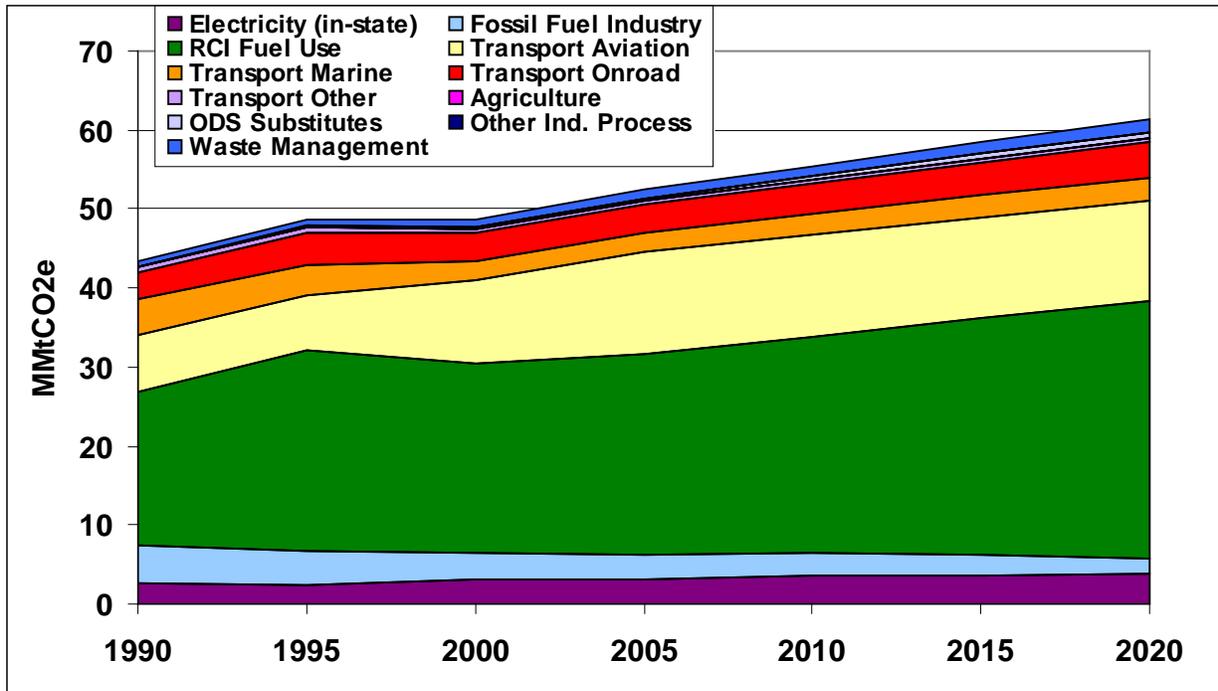


Figure ES-2. Alaska Gross GHG Emissions by Sector, 1990-2020: Historical and Projected



Notes: Fossil Fuel Industry emissions include emissions not associated with fuel combustion (fugitive CH₄). Fossil fuel combustion emissions are included in the RCI Fuel Use sector. RCI – direct fuel use in residential, commercial and industrial sectors. ODS – ozone depleting substance.

**Figure ES-3. Sector Contributions to Emissions Growth in Alaska,
1990-2020: Reference Case Projections**

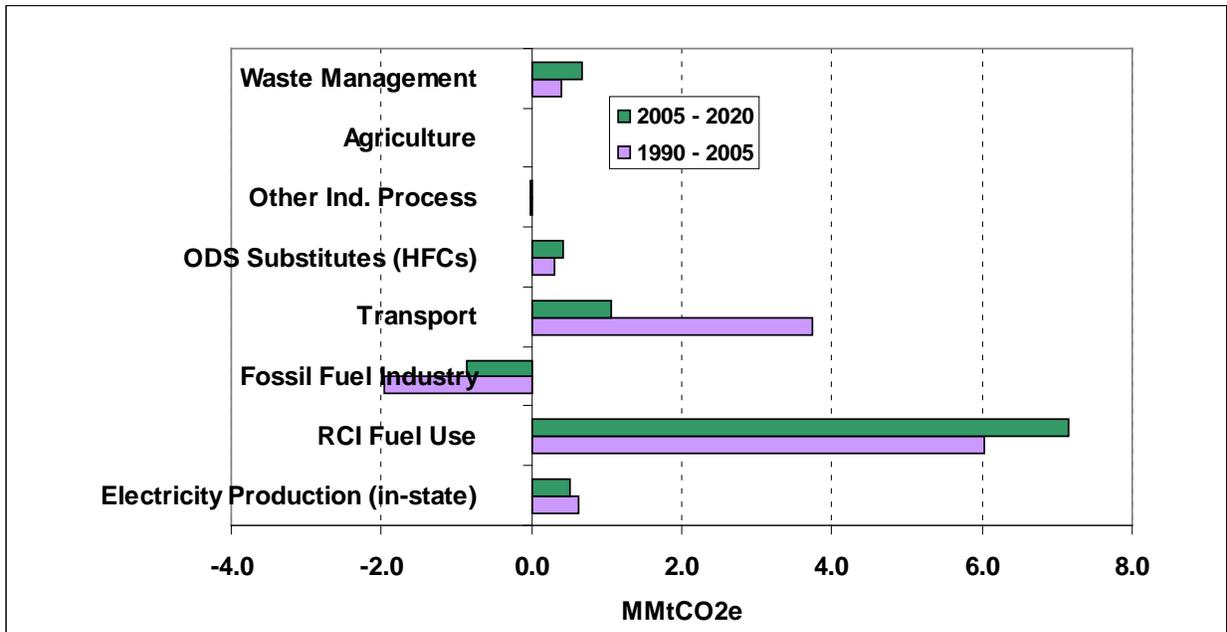


Table of Contents

Executive Summary	iii
Acronyms and Key Terms	ix
Acknowledgements.....	xii
Summary of Preliminary Findings.....	1
Introduction.....	1
Alaska Greenhouse Gas Emissions: Sources and Trends.....	2
Historical Emissions	4
Overview.....	4
A Closer Look at the Two Major Sources: RCI Fuel Use and Transportation.....	6
Reference Case Projections.....	8
Key Uncertainties and Next Steps	8
Approach.....	9
General Methodology	9
General Principles and Guidelines.....	10
Appendix A. Electricity Use and Supply.....	A-1
Appendix B. Residential, Commercial, and Industrial Fossil Fuel Combustion.....	B-1
Appendix C. Transportation Energy Use.....	C-1
Appendix D. Industrial Processes.....	D-1
Appendix E. Fossil Fuel Industries.....	E-1
Appendix F. Agriculture.....	F-1
Appendix G. Waste Management.....	G-1
Appendix H. Forestry.....	H-1
Appendix I. Inventory and Forecast for Black Carbon.....	I-1
Appendix J. Greenhouse Gases and Global Warming Potential Values: Excerpts from the <i>Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2000</i>	J-1

Acronyms and Key Terms

AEO – *Annual Energy Outlook*

Ag – Agriculture

ADEC – Alaska Department of Environmental Conservation

bbls – Barrels

BC – Black Carbon

Bcf – Billion cubic feet

BLM – United States Bureau of Land Management

BOC – Bureau of Census

BTU – British thermal unit

C – Carbon

CaCO₃ – Calcium Carbonate

CBM – Coal Bed Methane

CCS – Center for Climate Strategies

CFCs – chlorofluorocarbons

CH₄ – Methane*

CO₂ – Carbon Dioxide*

CO₂e – Carbon Dioxide equivalent*

CRP – Federal Conservation Reserve Program

EC – Elemental Carbon

eGRID – U.S. EPA's Emissions & Generation Resource Integrated Database

EIA – U.S. DOE Energy Information Administration

EIIP – Emissions Inventory Improvement Project (US EPA)

FIA – Forest Inventory Analysis

GHG – Greenhouse Gases*

GSP – Gross State Product

GWh – Gigawatt-hour

GWP - Global Warming Potential*

HFCs – Hydrofluorocarbons*

HNO₃ – Nitric acid

HWP – Harvested Wood Products

IPCC – Intergovernmental Panel on Climate Change*

kWh – Kilowatt-hour
LFGTE – Landfill Gas Collection System and Landfill-Gas-to-Energy
LMOP – Landfill Methane Outreach Program
LNG – Liquefied Natural Gas
LPG – Liquefied Petroleum Gas
Mg – Megagrams (equivalent to one metric ton)
Mt - Metric ton (equivalent to 1.102 short tons)
MMt – Million Metric tons
MPO – Metropolitan Planning Organization
MSW – Municipal solid waste
MW – Megawatt
N – Nitrogen
N₂O – Nitrous Oxide*
NO₂ – nitrogen dioxide*
NAICS – North American Industry Classification System
NASS – National Agricultural Statistics Service
NO_x – Nitrogen oxides
NSCR – Non-selective catalytic reduction
ODS – Ozone-Depleting Substances
OM – Organic Matter
PADD – Petroleum Administration for Defense Districts
PFCs – Perfluorocarbons*
PM – Particulate Matter
ppb – parts per billion
ppm – parts per million
ppt – parts per trillion
PV – Photovoltaic
RCI – Residential, Commercial, and Industrial
RPA – Resources Planning Act Assessment
RPS – Renewable Portfolio Standard
SAR – Second Assessment Report
SCR- Selective catalytic reduction

SED – State Energy Data

SF₆ – Sulfur Hexafluoride*

SGIT – State Greenhouse Gas Inventory Tool

Sinks – Removals of carbon from the atmosphere, with the carbon stored in forests, soils, landfills, wood structures, or other biomass-related products.

TAR – Third Assessment Report

T&D – Transmission and Distribution

TWh – Terawatt-hours

UNFCCC – United Nations Framework Convention on Climate Change

U.S. EPA – United States Environmental Protection Agency

U.S. DOE – United States Department of Energy

USDA – United States Department of Agriculture

USFS – United States Forest Service

USGS – United States Geological Survey

VMT – Vehicle-Miles Traveled

WAPA – Western Area Power Administration

WECC – Western Electricity Coordinating Council

W/m² – Watts per Square Meter

WMO – World Meteorological Organization*

WRAP – Western Regional Air Partnership

* - See Appendix J for more information.

Acknowledgements

CCS appreciates all of the time and assistance provided by numerous contacts throughout Alaska, as well as in other western states and at federal agencies. Thanks go to the many staff at several Alaska state agencies and universities for their inputs, and in particular to: Alice Edwards and Tom Chapple of the Alaska Department of Environment Quality, Division of Air Quality who provided key guidance and review for this analytical effort; Peter Crimp of the Alaska Energy Authority, Scott Goldsmith of the Institute of Social and Economic Research, and Mark Foster of MAFA Consulting for information in the electricity sector; and David McGuire and Michael Balshi of the University of Fairbanks, Alaska for their information and review of the forestry sector inventory.

The authors would also like to express their appreciation to the additional CCS reviewers: Katie Bickel, Michael Lazarus, Lewison Lem, and David Von Hippel.

Summary of Preliminary Findings

Introduction

The Center for Climate Strategies (CCS) prepared this report for the Alaska Department of Environmental Conservation (ADEC) under an agreement with the Western Governors' Association. This report presents initial estimates of base year and projected Alaska anthropogenic greenhouse gas (GHG) emissions and sinks for the period from 1990 to 2020. These estimates are intended to assist the State with an initial, comprehensive understanding of current and possible future GHG emissions for Alaska.

Historical GHG emissions estimates (1990 through 2005)² were developed using a set of generally accepted principles and guidelines for state GHG emissions inventories, as described in Section 2, relying to the extent possible on Alaska-specific data and inputs. The initial reference case projections (2006-2020) are based on a compilation of various existing projections of electricity generation, fuel use, and other GHG-emitting activities, along with a set of simple, transparent assumptions described in the appendices of this report.

This report covers the six types of gases included in the U.S. Greenhouse Gas Inventory: carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆). Emissions of these GHGs are presented using a common metric, CO₂ equivalence (CO₂e), which indicates the relative contribution of each gas to global average radiative forcing on a Global Warming Potential- (GWP-) weighted basis. The final appendix to this report provides a more complete discussion of GHGs and GWPs. Emissions of black carbon were also estimated. Black carbon (BC) is an aerosol species with a positive climate forcing potential (that is, the potential to warm the atmosphere, as GHGs do); however, black carbon currently does not have a GWP defined by the IPCC due to uncertainties in both the direct and indirect effects of BC on atmospheric processes (see Appendices I and J for more details). Therefore, except for Appendix I, all of the summary tables and graphs in this report cover emissions of just the six GHGs noted above.

It is important to note that the preliminary emission estimates for the electricity sector reflect the *GHG emissions associated with the electricity sources used to meet Alaska's demands*, corresponding to a *consumption-based* approach to emissions accounting (see Approach Section below). Another way to look at electricity emissions is to consider the *GHG emissions produced by electricity generation facilities in the State*. Because Alaska has very limited electricity imports or exports, the GHG emissions on a production-basis are the same as GHG emissions from a consumption-basis. CCS introduces this concept of consumption- versus production-based emissions, since in other states, electricity imports and exports are an important issue.

² The last year of available historical data varies by sector; ranging from 2000 to 2005.

Alaska Greenhouse Gas Emissions: Sources and Trends

Table 1 provides a summary of GHG emissions estimated for Alaska by sector for the years 1990, 2000, 2005, 2010, and 2020. In the sections below, we discuss GHG emission sources (positive, or *gross*, emissions) and sinks (negative emissions) separately in order to identify trends, projections and uncertainties for each.

The next section of the report provides a summary of the historic emissions (1990 through 2005) followed by a summary of the forecasted reference case projection year emissions (2006 through 2020), key uncertainties, and suggested next steps. CCS also provides an overview of the general methodology, principles, and guidelines followed for preparing the inventories. Appendices A through H provide the detailed methods, data sources, and assumptions for each GHG sector.

Appendix I provides information on 2002 and 2018 BC estimates for Alaska. CCS estimated that BC emissions in 2002 ranged from 1.9 – 4.0 MMtCO₂e with a mid-point estimate of 3.0 MMtCO₂e. A range is estimated based on the uncertainty in the global modeling analyses that serve as the basis for converting BC mass emissions into their carbon dioxide equivalents (see Appendix I for more details). Since the IPCC has not yet assigned a global warming potential for BC, CCS has excluded these estimates from the GHG summary shown in Table 1 below. Based on an assessment of 2018 forecasted emissions for the primary BC contributors from the Western Regional Air Partnership (WRAP), it is estimated that BC emissions will decrease by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors. Appendix I contains a detailed breakdown of emissions contribution by source sector.

Appendix J provides background information on GHGs and climate-forcing aerosols.

Table 1. Alaska Historical and Reference Case GHG Emissions, by Sector^a

(Million Metric Tons CO ₂ e)	1990	2000	2005	2010	2020	Explanatory Notes for Projections
Electricity Production	2.6	3.1	3.2	3.6	3.7	
Coal	0.4	0.8	0.6	0.6	0.6	See electric sector assumptions in appendix
Natural Gas	1.9	1.9	2.1	2.1	2.1	
Oil	0.3	0.5	0.6	0.9	1.0	
Net Exported Electricity	0	0	0	0	0	
Residential/Commercial	3.8	4.3	3.9	3.9	4.1	
Coal	0.8	0.8	0.7	0.7	0.7	Based on USDOE regional projections
Natural Gas	1.8	2.2	1.9	1.9	2.1	Based on USDOE regional projections
Oil	1.2	1.3	1.3	1.3	1.3	Based on USDOE regional projections
Wood (CH ₄ and N ₂ O)	0.02	0.01	0.02	0.02	0.02	Based on USDOE regional projections
Industrial (Non-Fossil Prod.)	15.7	19.6	21.6	23.5	28.5	
Coal	0.00	0.001	0.001	0.001	0.001	Based on USDOE regional projections
Natural Gas	13.2	17.3	18.5	19.9	24.4	Based on USDOE regional projections
Oil	2.4	2.4	3.1	3.6	4.1	Based on USDOE regional projections
Wood (CH ₄ and N ₂ O)	0.01	0.00	0.00	0.00	0.00	Based on USDOE regional projections
Transportation	15.6	17.1	19.4	19.8	20.4	
Aviation	7.2	10.6	12.9	12.9	12.5	FAA aircraft operations forecasts DEC commercial marine inventory growth factors
Marine Vessels	4.4	2.4	2.4	2.6	3.0	
Onroad Vehicles	3.4	3.7	3.6	3.9	4.4	WRAP inventory VMT projections Historical trends and USDOE regional projections
Rail and Other	0.6	0.4	0.4	0.4	0.5	
Fossil Fuel Industry	4.9	3.2	3.0	2.9	2.1	
Natural Gas Industry	0.2	0.4	0.5	0.4	0.4	Historical trends and DNR natural gas production forecasts Historical trends and DNR oil production forecasts
Oil Industry	4.7	2.8	2.5	2.4	1.7	
Coal Mining (Methane)	0.01	0.01	0.01	0.01	0.01	Historical trend
Industrial Processes	0.05	0.2	0.3	0.5	0.7	
Limestone and Dolomite Use	0.000	0.000	0.01	0.01	0.01	Alaska manufacturing employment growth National projections for 2004-2009 (USGS)
Soda Ash	0.01	0.01	0.01	0.01	0.01	
ODS Substitutes	0.001	0.2	0.3	0.4	0.7	EPA 2004 ODS cost study report
SF ₆ from Electric Utilities	0.04	0.03	0.02	0.02	0.01	Based on national projections (USEPA)
Waste Management	0.6	0.9	1.0	1.2	1.7	
Solid Waste Management	0.6	0.8	1.0	1.1	1.6	Projected based on 1995-2005 trend
Wastewater Management	0.1	0.1	0.1	0.1	0.1	Projected based on population
Agriculture	0.05	0.05	0.05	0.06	0.07	
Manure Management	0.001	0.002	0.004	0.01	0.01	USDA livestock projections
Enteric Fermentation	0.01	0.02	0.02	0.02	0.03	USDA livestock projections
Agricultural Soils	0.04	0.04	0.03	0.03	0.03	Projected based on historical trend
Total Gross Emissions	43.3	48.6	52.4	55.4	61.4	
<i>increase relative to 1990</i>		12%	21%	28%	42%	
Forestry and Land Use	-0.3	-1.4	-1.4	-1.4	-1.4	Projections held constant at 2000 level.
Net Emissions (incl. forestry*)	43.0	47.2	51.0	54.0	60.0	
<i>increase relative to 1990</i>		10%	19%	33%	39%	

^a Totals may not equal exact sum of subtotals shown in this table due to independent rounding. NA = not available.

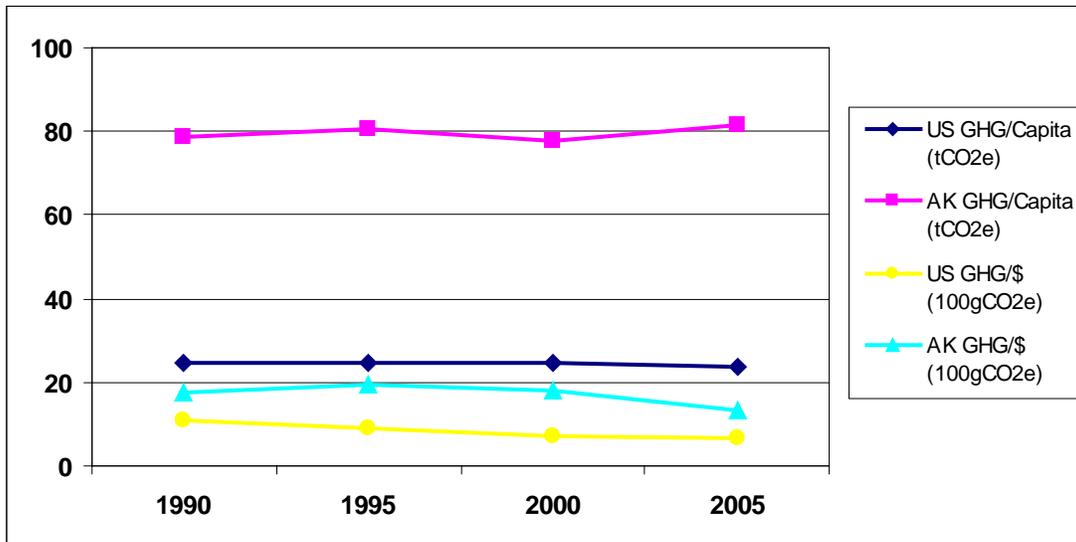
Historical Emissions

Overview

Our analyses suggest that in 2005, activities in Alaska accounted for approximately 52.4 million metric tons (MMt) of *gross*³ CO₂e emissions, an amount equal to 0.7% of total U.S. gross GHG emissions. Alaska's gross GHG emissions are rising at about the same rate as those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Alaska's gross GHG emissions increased by about 12% from 1990 to 2000, while national emissions rose by 14% during the same period.

On a per capita basis, Alaska activities emit about 82 metric tons (Mt) of CO₂e annually; significantly higher than the national average of 25 MtCO₂e/yr. Figure 1 illustrates the State's emissions (metric tons) per capita and per dollar of economic output. It also shows that, like the nation as a whole, per capita emissions have changed relatively little, while economic growth has exceeded emissions growth in Alaska throughout the 1995-2005 period (leading to declining rates of GHG emissions per dollar of economic output). From 1990 to 2004, emissions per unit of gross product dropped by 40% nationally (2004 are the latest US estimates). In Alaska, gross product emissions dropped by 23% from 1990 to 2005. Emissions from the fossil fuel industry and transportation (notably aircraft and commercial marine) sectors contribute to the large differences seen between Alaska's per capita emission rates and the national average.

Figure 1. Alaska and US Gross GHG Emissions, Per Capita and Per Unit Gross Product



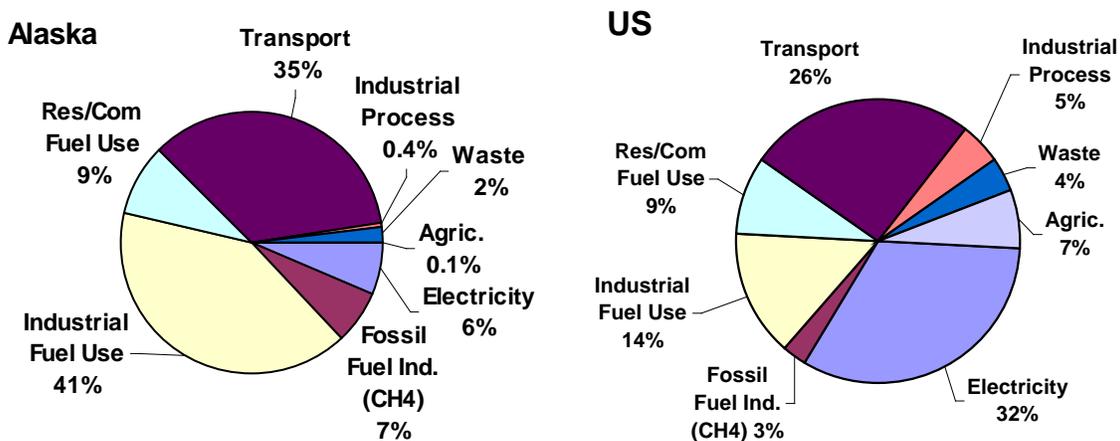
Residential, commercial, and industrial (RCI) fossil fuel combustion and transportation are the State's principal GHG emissions sources. RCI fossil fuel combustion accounted for 41% of

³ Excluding GHG emissions removed due to forestry and other land uses and excluding GHG emissions associated with exported electricity.

Alaska's *gross* GHG emissions in 2000, as shown in Figure 2. The transportation sector accounted for 39% of gross GHG emissions in 2000. Electricity production and the fossil fuel industry each accounted for 7% of gross GHG emissions. The remaining sectors – agriculture, landfills and wastewater management facilities, and industrial processes – accounted for less than 3% of the State's emissions in 2000. Industrial process emissions comprised only 0.4% of State GHG emissions in 2000, but these emissions are rising rapidly due to the increasing use of HFC as substitutes for ozone-depleting chlorofluorocarbons.⁴

Figure 3 provides both the historical and projected gross emission estimates for all source sectors. Figure 4 is a chart showing the contribution for each sector to emissions growth both historically (1990-2005) and for the reference case forecast (2005-2020). As shown in this figure, both the RCI fuel combustion and transportation sectors are important contributors to emissions growth, both historically and in the future projected emissions. Non-combustion emissions for the fossil fuel industry show declining growth both historically and in the future as existing oil and gas production fields are expected to decline. As described in Appendix E, the reference case forecast does not assume significant new oil and gas leases coming into production before 2020 (an important area for future assessment for GHG implications).

Figure 2. Gross GHG Emissions by Sector, 2000, Alaska and US

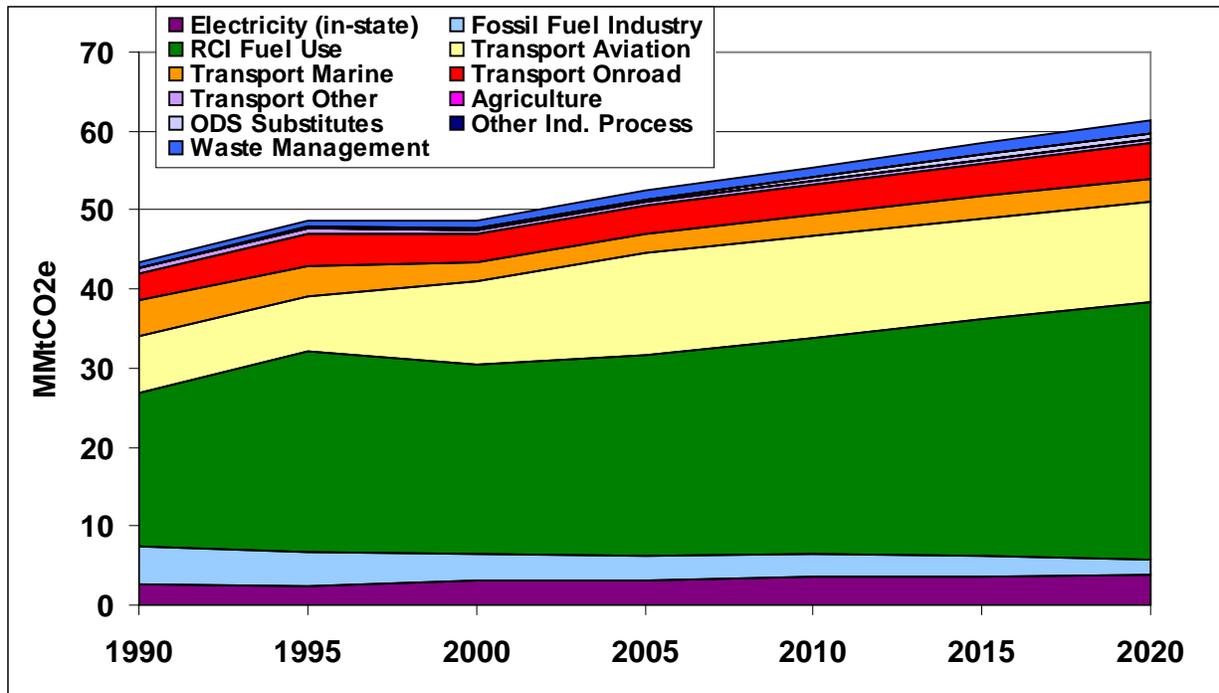


⁴ Chlorofluorocarbons (CFCs) are also potent GHGs; they are not, however, included in GHG estimates because of concerns related to implementation of the Montreal Protocol. See final Appendix (Appendix I).

A Closer Look at the Two Major Sources: RCI Fuel Use and Transportation

Activities in the residential, commercial, and industrial⁵ (RCI) sectors produce GHG emissions when fuels are combusted to provide space heating, process heating, and other applications. In 2000, combustion of oil, natural gas, coal, and wood in the RCI sectors contributed about 50% of Alaska's gross GHG emissions, much higher than RCI sector contribution for the nation (23%).

Figure 3. Alaska Gross GHG Emissions by Sector, 1990-2020: Historical and Projected



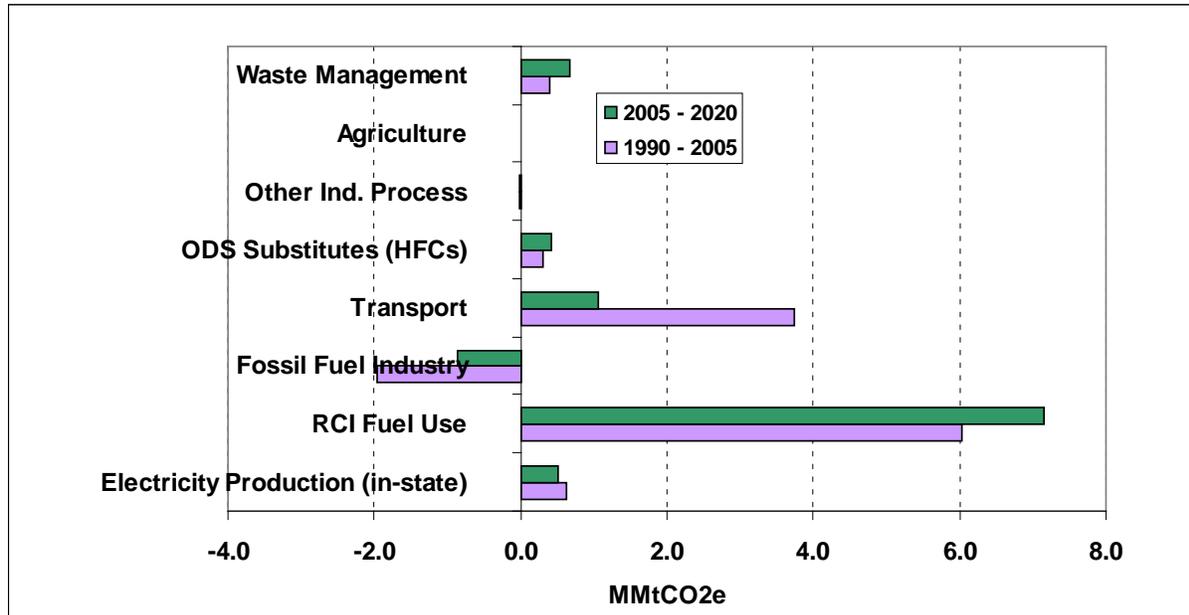
Notes: Fossil Fuel Industry emissions include emissions not associated with fuel combustion (fugitive CH₄). Fossil fuel combustion emissions are included in the RCI Fuel Use sector. RCI – direct fuel use in residential, commercial and industrial sectors. ODS – ozone depleting substance.

By 2005, the RCI sector emissions were at about 49% (25.5 MMtCO₂e) of gross GHG emissions. In 2005, the residential sector's share of total RCI emissions from direct fuel use was 7% (1.8 MMtCO₂e), the commercial sector accounted for 8% (2.0 MMtCO₂e), and the industrial sector's share of total RCI emissions from direct fuel use was 85% (21.6 MMtCO₂e). Overall emissions for the RCI sector (excluding those associated with electricity consumption) are expected to increase by 28% between 2005 and 2020. Emissions from the residential and commercial sectors are projected to increase by 6% and 5% between 2005 and 2020, respectively. The strongest growth is expected from the industrial sector, which is projected to increase 32% between 2005 and 2020.⁶

⁵ The industrial sector includes emissions associated with agricultural energy use and fuel used by the fossil fuel production industry.

⁶ See Appendix B for more details. Given the forecasted decline in non-combustion emissions for the fossil fuel industry; the increase in the industrial fossil fuel consumption seems odd; however, ADEC contacts indicate that

Figure 4. Sector Contributions to Emissions Growth in Alaska, 1990-2020: Historic and Reference Case Projections



*RCI – direct fuel use in residential, commercial and industrial sectors; ODS – ozone depleting substance.

The transportation sector accounted for 35% (17.1 MMtCO₂e) of Alaska’s gross GHG emissions in 2000. Emissions are projected to increase to 20.4 MMtCO₂e (33% of gross GHG emissions) in 2020. Jet fuel consumption accounts for the largest share of transportation GHG emissions. Emissions from jet fuel consumption increased by about 59% from 1990-2002 to cover almost 63% of total transportation emissions in 2002. GHG emissions from marine fuel consumption decreased by 43% from 1990 to 2002, and in 2002 accounted for 14% of GHG emissions from the transportation sector. Emissions from onroad gasoline grew by only 1% between 1990 and 2002 and onroad diesel grew by 8% during this period. In 2002, onroad gasoline and diesel accounted for 12% and 8% of total transportation emissions, respectively. Emissions from all other categories combined (aviation gasoline, locomotives, natural gas and LPG, and oxidation of lubricants) contributed slightly over 2% of total transportation emissions in 2002.

It is important to note that the jet fuel emissions include fuel that is purchased in-state but is not necessarily consumed within Alaska’s airspace. This accounting issue is also present in the inventories of other states prepared by CCS, where international passenger and cargo transportation emissions are concerned. On the other hand, fuel purchased outside of the state for aircraft that enter the state are not included in the emission estimates presented in this report. The size of the contribution from the transportation - aviation sector shown in Figure 3 above reflects the importance

natural gas combustion is expected to increase significantly in future years since more fuel is consumed to extract oil and gas as the production in existing fields declines. This is an area that should be investigated further during future work. The industrial fossil fuel consumption projections are based on the regional EIA AEO forecast data for the Pacific Region.

of this industry in Alaska.

Reference Case Projections

Relying on a variety of sources for projections of electricity and fuel use, as noted below and in the Appendices, we developed a simple reference case projection of GHG emissions through 2020. As illustrated in Figure 3 and shown numerically in Table 1, under the reference case projections, Alaska gross GHG emissions continue to grow steadily, climbing to 61.4 MMTCO₂e by 2020, 42% above 1990 levels. Residential, commercial, and industrial (RCI) fossil fuel use is projected to be the largest contributor to future emissions growth with the industrial subsector being the key contributor. Additional details on the assumptions used to estimate future GHG emissions are provided in the applicable technical appendices to this report.

Key Uncertainties and Next Steps

Some data gaps exist in this inventory, and particularly in the reference case projections. Key tasks that should be performed in future updates include review and revision of key drivers, such as the electricity and transportation fuel use growth rates that will be major determinants of Alaska's future GHG emissions (See Table 2). These growth rates are driven by uncertain economic, industrial, demographic, and land use trends (including growth patterns and transportation system impacts), all of which deserve closer review and discussion.

Perhaps the variables with the most important implications for the State's GHG emissions are the assumptions on air travel and industrial sector growth. In the electricity generation sector, the important assumptions include a large renewable energy mix in the new generation sources (80% renewable). Finally, uncertainty remains regarding the estimates for historic GHG sinks from forestry, and projections for these emissions may affect the net GHG emissions in Alaska.

Table 3. Key Annual Growth Rates for Alaska, Historical and Projected

Key Parameter	1990-2005	2005-2020	Sources
Population	1.0%	0.7%	Alaska Department of Labor and Workforce Development
Employment Goods Services	2.6% 2.5%	1.2% 1.4%	Alaska Department of Labor and Workforce Development, 2004-2014 Forecast trend assumed to continue through 2020
Electricity Sales	2.2%	1.7%	Historic from EIA data, projections are CCS assumptions based on extending 2000-2005 growth
Vehicle Miles Traveled	1.7%	1.3%	Alaska Department of Transportation and Public Facilities, Western Region Air Partnership (WRAP) Mobile Source Inventory

* Population and employment projections for Alaska were used together with US DOE's Annual Energy Outlook 2006 projections of changes in fuel use on a per capita and per employee, as relevant for each sector. For instance, growth in Alaska's residential natural gas use is calculated as the Alaska population growth times the change in per capita natural gas use for the Pacific region.

Emissions of aerosols, particularly black carbon from fossil fuel combustion, could have significant impacts in terms of radiative forcing (that is, climate impacts). Methodologies for conversion of black carbon mass estimates and projections to global warming potential involve significant uncertainty at present, but CCS has developed and used a recommended approach for estimating black carbon emissions based on methods used in other States. Current estimates suggest a 6% CO₂e contribution overall from BC emissions, as compared to the CO₂e contributed from the gases (see Appendix I).

Approach

The principal goal of compiling the inventories and reference case projections presented in this document is to provide the State, with a general understanding of Alaska's historical, current, and projected (expected) GHG emissions. The following explains the general methodology and the general principles and guidelines followed during development of these GHG inventories for Alaska.

General Methodology

CCS prepared this analysis in close consultation with Alaska agencies, in particular, with the ADEC staff. The overall goal of this effort is to provide simple and straightforward estimates, with an emphasis on robustness, consistency and transparency. As a result, we rely on reference forecasts from best available state and regional sources where possible. Where reliable forecasts are lacking, we use straightforward spreadsheet analysis and linear extrapolations of historical trends rather than complex modeling.

In most cases, we follow the same approach to emissions accounting for historical inventories used by the US EPA in its national GHG emissions inventory⁷ and its guidelines for States.⁸ These inventory guidelines were developed based on the guidelines from the Intergovernmental Panel on Climate Change, the international organization responsible for developing coordinated methods for national GHG inventories.⁹ The inventory methods provide flexibility to account for local conditions. The key sources of activity and projection data are shown in Table 4. Table 4 also provides the descriptions of the data provided by each source and the uses of each data set in this analysis.

General Principles and Guidelines

A key part of this effort involves the establishment and use of a set of generally accepted accounting principles for evaluation of historical and projected GHG emissions, as follows:

- **Transparency:** We report data sources, methods, and key assumptions to allow open review and opportunities for additional revisions later based on input from others. In addition, we will report key uncertainties where they exist.
- **Consistency:** To the extent possible, the inventory and projections will be designed to be externally consistent with current or likely future systems for state and national GHG emission reporting. We have used the EPA tools for state inventories and projections as a starting point. These initial estimates were then augmented and/or revised as needed to conform with state-based inventory and base-case projection needs. For consistency in making reference case projections¹⁰, we define reference case actions for the purposes of projections as those *currently in place or reasonably expected over the time period of analysis*.
- **Comprehensive Coverage of Gases, Sectors, State Activities, and Time Periods.** This analysis aims to comprehensively cover GHG emissions associated with activities in Alaska. It covers all six GHGs covered by U.S. and other national inventories: CO₂, CH₄, N₂O, SF₆, HFCs, and PFCs and black carbon. The inventory estimates are for the year 1990, with subsequent years included up to most recently available data (typically 2002 to 2005), with projections to 2010 and 2020.
- **Priority of Significant Emissions Sources:** In general, activities with relatively small emissions levels may not be reported with the same level of detail as other activities.

⁷ US EPA, Feb 2005. *Draft Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003*.
<http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html>.

⁸ <http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html>.

⁹ <http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm>.

¹⁰ “Reference case” refers to a projection of the current or “base year” inventory to one or more future years under business-as-usual forecast conditions (for example, existing control programs and economic growth).

Table 4. Key Sources for Alaska Data, Inventory Methods, and Growth Rates

Source	Information provided	Use of Information in this Analysis
US EPA State Greenhouse Gas Inventory Tool (SGIT)	US EPA SGIT is a collection of linked spreadsheets designed to help users develop State GHG inventories. US EPA SGIT contains default data for each State for most of the information required for an inventory. The SGIT methods are based on the methods provided in the Volume 8 document series published by the Emissions Inventory Improvement Program (http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html)	Where not indicated otherwise, SGIT is used to calculate emissions from residential/commercial/industrial fuel combustion, industrial processes, transportation, agriculture and forestry, and waste. We use SGIT emission factors (CO ₂ , CH ₄ and N ₂ O per BTU consumed) to calculate energy use emissions.
US DOE Energy Information Administration (EIA) State Energy Data (SED)	EIA SED source provides energy use data in each State, annually to 2001.	EIA SED is the source for most energy use data. We also use the more recent data for electricity and natural gas consumption (including natural gas for vehicle fuel) from the EIA website for years after 2001. Emission factors from US EPA SGIT are used to calculate energy-related emissions.
US DOE Energy Information Administration Annual Energy Outlook 2006 (AEO2006)	EIA AEO2006 projects energy supply and demand for the US from 2005 to 2030. Energy consumption is estimated on a regional basis. Alaska is included in the Pacific Census region (AK, CA, HI, OR, and WA)	EIA AEO2006 is used to project changes in per capita (residential) and per employee (commercial/industrial) energy consumption
American Gas Association – Gas Facts	Natural gas transmission and distribution pipeline mileage.	Pipeline mileage from Gas Facts used with SGIT to estimate natural gas transmission and distribution emissions.
US EPA Landfill Methane Outreach Program (LMOP)	LMOP provides landfill waste-in-place data.	Waste-in-place data used to estimate annual disposal rate, which was used with SGIT to estimate emissions from solid waste, with additional data from ADEC staff.
US Forest Service	Under development	Under development
USDS National Agricultural Statistics Service (NASS)	USDA NASS provides data on crops and livestock.	Crop production data used to estimate agricultural residue and agricultural soils emissions; livestock population data used to estimate manure and enteric fermentation emissions

- **Priority of Existing State and Local Data Sources:** In gathering data and in cases where data sources conflicted, we placed highest priority on local and state data and

analyses, followed by regional sources, with national data or simplified assumptions such as constant linear extrapolation of trends used as defaults where necessary.

- **Use of Consumption-Based Emissions Estimates:** To the extent possible, we estimated emissions that are caused by activities that occur in Alaska. For example, we reported emissions associated with the electricity consumed in Alaska. The rationale for this method of reporting is that it can more accurately reflect the impact of State-based policy strategies such as energy efficiency on overall GHG emissions, and it resolves double counting and exclusion problems with multi-emissions issues. This approach can differ from how inventories are compiled, for example, on an in-state production basis, in particular for electricity. *As mentioned previously, since there are no significant electricity imports to or exports from Alaska, the production-based estimates are the same as the consumption-based estimates.*

If ADEC decides to refine this analysis, they may also consider estimating other sectoral emissions on a consumption basis, such as accounting for emissions from combustion of transportation fuel used in Alaska, but purchased out-of-state. In some cases this can require venturing into the relatively complex terrain of life-cycle analysis. In general, CCS recommends considering a consumption-based approach where it will significantly improve the estimation of the emissions impact of potential mitigation strategies. [For example re-use, recycling, and source reduction can lead to emission reductions resulting from lower energy requirements for material production (such as paper, cardboard, and aluminum), even though production of those materials, and emissions associated with materials production, may not occur within the State.]

Details on the methods and data sources used to construct the inventories and forecasts for each source sector are provided in the following appendices:

- Appendix A. Electricity Use and Supply.
- Appendix B. Residential, Commercial, and Industrial (RCI) Fossil Fuel Combustion.
- Appendix C. Transportation Energy Use.
- Appendix D. Industrial Processes.
- Appendix E. Fossil Fuel Industries.
- Appendix F. Agriculture.
- Appendix G. Waste Management.
- Appendix H. Forestry.

Appendix I contains a discussion of the inventory and forecast for black carbon. Appendix J provides additional background information from the US EPA on greenhouse gases and global warming potential values.

Appendix A. Electricity Use and Supply

This Appendix describes Alaska's electricity sector and the greenhouse gas (GHG) emissions associated with this sector from 1990 to the present. The assumptions used to develop the reference case projections are described and the resulting GHG emissions are summarized.

As noted in the main report, a key question for many States to consider when developing GHG inventories is how to treat GHG emissions that result from generation of electricity that is produced outside the State to meet electricity needs in the State – or the opposite case of electricity produced in the State to provide electricity for customers in other states. In other words, should the State consider the GHG emissions associated with the State's electricity consumption, with its electricity production, or with some combination of the two? This issue is not as important for Alaska, since its electric sector is stand-alone. However, the *consumption-based* and *production-based* terminology is used in this Appendix for Alaska to allow for simple comparison with GHG reports for other states.

Electricity Consumption

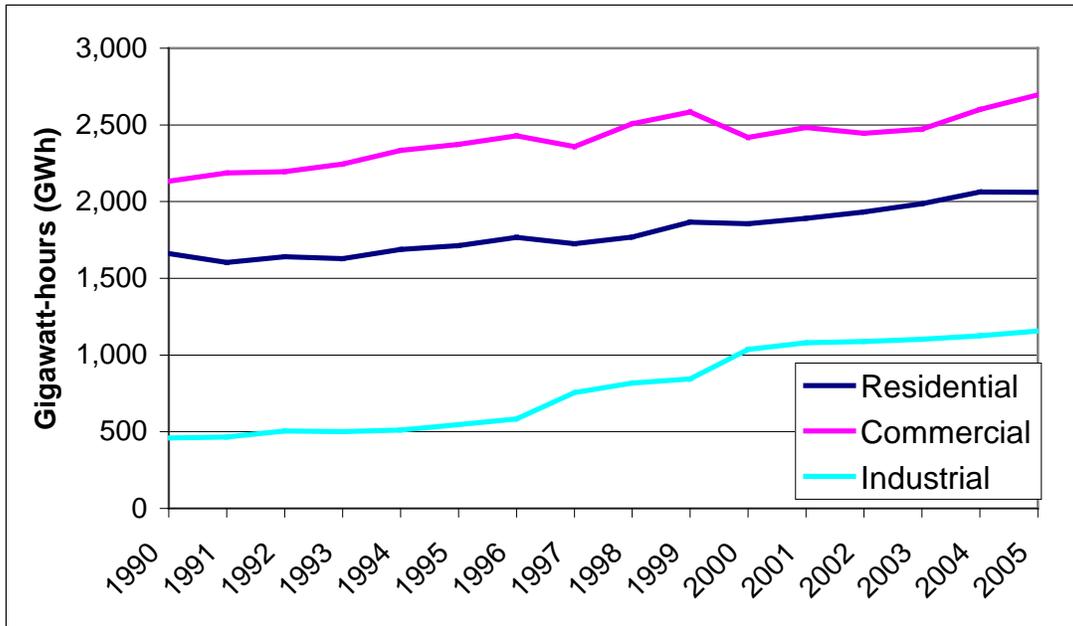
At about 8,800 kilowatt-hours (kWh) per capita per year based on 2004 data, Alaska has relatively low electricity consumption for its population. By way of comparison, the per capita consumption for the U.S. was about 12,000 kWh per year.¹¹ Many factors influence a state's per capita electricity consumption, including the impact of weather on demand for cooling and heating, the size and type of industries in the State, and the type and efficiency of equipment in use in the residential, commercial and industrial sectors.

As shown in Figure A1, electricity sales in Alaska's residential and commercial sectors have generally increased modestly from 1990 through 2005. The industrial sector electricity sales are characterized by strong growth from 1997 to 2000, but limited growth in other time periods. Overall, total electricity consumption increased at an average annual rate of 2.2 percent from 1990 to 2005, which can be compared with the average population growth rate of 1.0 percent per year and gross state product increases averaging about 3.8 percent per year over the same period.¹²

¹¹ US Census Bureau for US population, Energy Information Administration for electricity sales.

¹² Population from Alaska Department of Labor and Workforce Development, "Workforce Information," Home (<http://almis.labor.state.ak.us/>), Population & Census, Estimates & Projections, Population Data Tables "Alaska Population Estimates 2000-2005,". Gross State Production from Bureau of Economic Analysis. <http://bea.gov/bea/newsrelarchive/2006/gsp1006.xls>.

Figure A1. Electricity Consumption by Sector in Alaska, 1990-2005¹³



Source: EIA State Energy Data (1990-2002) and EIA Electric Power Annual (2003-2005).

Projections for electricity sales from 2006 through 2020 are based on extrapolating the trends in electricity growth from 2000 to 2005, rather than relying on existing projections of electricity sales. In Alaska, more than 70 different entities provide electricity to consumers. In 2004, the State had 21 Investor-owned utilities, 34 public entities and 18 electric co-operatives. These entities are not required to submit planning reports to the Regulatory Commission of Alaska, or to any other source. Collecting information from each utility was beyond the resources of this project, and may not even be feasible since many utilities are unlikely to have such plans. Other potential sources for electricity sales projections, such as the Institute of Social and Economic Research (ISER) at the University of Alaska and the documents from the Alaska Energy Task Force, had not completed state-wide projections recently.¹⁴ Representatives from both ISER and the Alaska Energy Authority suggested future growth is likely to follow historic trends.¹⁵ Table A1 reports historic and projected annual average growth rates.

¹³ Note from 1990-2002, the EIA data includes a category referred to as “other,” which included lighting for public buildings, streets, and highways, interdepartmental sales, and other sales to public authorities, agricultural and irrigation sales where separately identified, electrified rail and various urban transit systems (such as automated guideway, trolley, and cable). To report total electricity in Figure A1, the sales from the “other” category are included with the commercial sector. The decision to include these with commercial rather than the other sectors is based on comparing the trends of electricity sales from 2000-2002 with 2003 sales.

¹⁴ Email from Scott Goldsmith, ISER, January 10, 2007.

¹⁵ Email from Scott Goldsmith, ISER, January 10, 2007, personal communication with Peter Crimp, Alaska Energy Authority, January 16, 2007. Also, personal communication, Mark Foster, MAFA.

Table A1. Electricity Growth Rates, historic and projected

	Historic		Projections
	1990-2000	2000-2005	2005-2020
Residential	1.1%	2.1%	2.1%
Commercial	1.3%	1.5%	1.5%
Industrial	8.5%	1.7%	1.7%
Total	2.2%	1.7%	1.7%

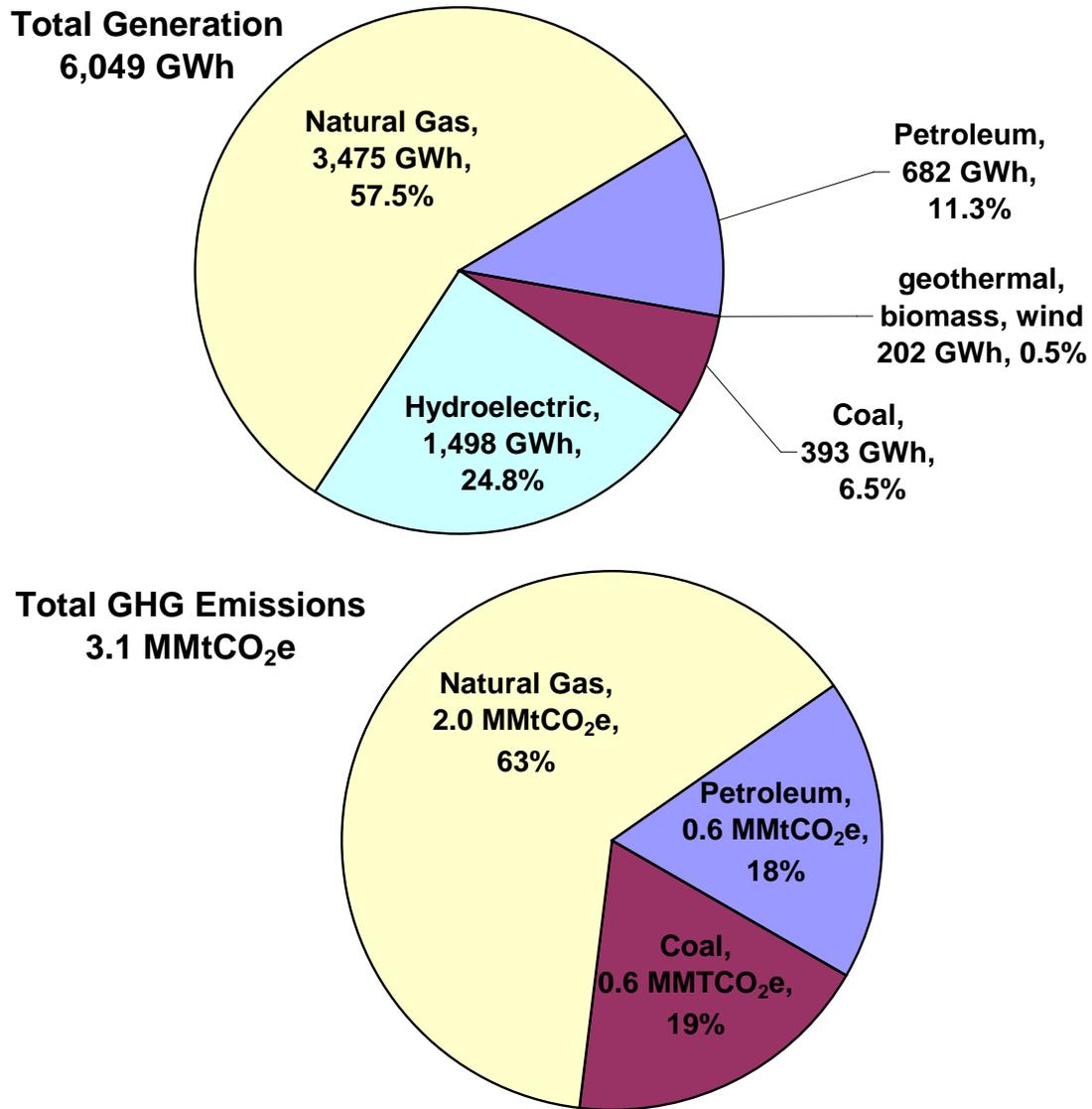
Source: Historic from EIA data, projections are CCS assumptions based on extending 2000-2005 growth.

Electricity Generation – Alaska’s Power Plants

The following section provides information on GHG emissions and other activity associated with power plants in Alaska.

As displayed in Figure A2, natural gas figures prominently in electricity generation and accounts for 63 percent of the GHG emissions from power plants in Alaska. Hydro-electric and petroleum-fired plants also provided significant electricity generation. To calculate total GHG emissions from electricity production in Alaska, CCS applied SGIT emission factors to annual energy consumption data extracted from EIA’s State Energy Data.

Figure A2. Electricity Generation and CO₂ Emissions from Alaska Power Plants, 2004



Source: Generation data from EIA Electric Power Annual spreadsheets, GHG emissions calculated from EIA data on fuel consumption and SGIT GHG emission factors.

Table A2 shows the growth in generation by fuel type between 1990 and 2004 from power plants in Alaska. Overall generation grew by 35 percent over the 15 years. Petroleum-fired generation has had particularly strong growth, doubling between 1990 and 2004. Hydro generation also grew significantly during this period. Natural gas-fired generation grew more slowly but remains the dominant source of electricity in the State.

Table A2. Growth in Electricity Generation in Alaska 1990-2004

	Generation (GWh)		Growth
	1990	2004	
Coal	312	393	26%
Hydroelectric	975	1,498	54%
Natural Gas	2,870	3,475	21%
biomass, wind, geothermal	0	1	n/a
Petroleum	337	682	102%
Total	4,493	6,049	35%

Source: EIA data, generation from electric sector, excludes electricity generation from industrial and commercial sector.

Future Generation and Emissions

Estimating future generation and GHG emissions from Alaska power plants requires estimation of new power plant additions and production levels from new and existing power plants. There are, of course, large uncertainties, especially related to the timing and nature of new power plant construction.

The future mix of plants in Alaska remains uncertain as the trends in type of new builds are influenced by many factors. Recently, new power plants in Alaska have been a mix of wind, geothermal, hydroelectric and naphtha. Coal dominates the capacity of the new plants that have been proposed for construction over the next ten years, but not all proposed plants will be built. A variety of other energy sources have been proposed for other new plants in Alaska. Table A3 presents data on new and proposed plants in Alaska.

Individual proposed plants are not modeled in the reference case projections, but the mix of types of proposed plants are considered when developing assumptions for the projections.

Table A3. New and Proposed Power Plants in Alaska

	Plant Name	Fuel	Status	Capacity	Estimated Annual		Notes
				MW	Generation GWh	Emissions MMtCO ₂ e	
New plants	Kotzebue Wind project expansion	wind	2005/2006	0.5	1.1	0.0	This expansion is additional to the 0.5MW built in 1997 and 1999.
	South Fork Hydro	Hydroelectric	In-service 2006	2	6.4	0.0	
	Chena Hot Springs	Geothermal	In-service 2006	0.4	3	negligible	The first geothermal power plant in Alaska. It is a small-scale unit, using organic rankine cycle (ORC) technology to produce power from a low temperature resource.
	North Pole Expansion Project	Naphtha	30 MW tested in 2006 In-service 2007	60	447	0.4	
Proposed plants	Lake Dorothy Hydro	Hydro electric	under construction	14.3	75	0.0	
	Sand Point	wind	under construction	1	3	0.0	
	Cascade Creek	Hydroelectric	Proposed	80	420	0.0	
	Swan Lake at Thomas Bay	Hydroelectric	Proposed	30	166	0.0	
	Scenery Creek at Thomas Bay	Hydroelectric	Proposed	20	103	0.0	
	Takatzt Lake	Hydroelectric	Proposed	20	82	0.0	
	Allison Creek	Hydroelectric	Proposed	5	20	0.0	
	Chakachamna	Hydroelectric	Proposed	430	1,300	0.0	
	Fire Island	Wind	Proposed	80	20	0.0	
	Healy	coal	Proposed	200	1,489	1.3	Usibelli Coal Mine proposed 5/2003, in service TBD
	Kenai	coal - IGCC	Proposed	350	2,606	2.2	feasibility study 2005, board decision 2008, in service end of 2011
	Galena	Nuclear	Proposed	10	74	0.0	Galena city council accepted a proposal from Toshiba to test its "nuclear battery" reactor design

- Sources:
- Kotzebue Wind www.awea.org
 - South Fork Hydro <http://www.lowimpacthydro.org/appdetails.asp?x=29>
 - Galena Hot Springs <http://www.geo-energy.org/publications/reports/>
 - North Pole Expansion <http://www.gvea.com/about/generation/npe/>
 - Lake Dorothy http://www.state.ak.us/rca/Hydroelectric/040427_Projects.pdf
<http://www.seconference.org/pdf/Stone-JuneautoAdmiraltyIntertie&LakeDorothy.pdf>
 - Sand Point Personal Communication, P. Crimp Alaska Energy Authority
 - Cascade Creek, Swan Lake, Scenery Creek, and Takatzt Lake AK-BC Intertie Feasibility Study, Dec 2006 draft
AK Energy Authority. <http://www.aidea.org/aea/PDF%20files/1-7-2007AK-BCDraft%20Report.pdf>
 - Chakachamna Personal Communication, P. Crimp Alaska Energy Authority
 - Fire Island <http://www.akenergyauthority.org/PDF%20files/fireisland.pdf>
 - Healy National Energy Technology Lab, Coal Plant Database
 - Kenai <http://www.adn.com/opinion/view/story/8532439p-8426333c.html>
 - Galena Nuclear http://www.alaskajournal.com/stories/122604/loc_20041226003.shtml

Notes: The above table is not a comprehensive list of plants. Instead it reflects information that was available through basic search of public data. Generation estimates are based on capacity factors of 0.85 for base load coal and nuclear and 0.35 for wind. Capacity factors for hydro are site dependent and provided by source reports. Emissions estimates based on heat rates of 9,000 BTU/kWh of coal.

Given the many factors affecting electricity-related emissions and a diversity of assumptions by stakeholders within the electricity sector, developing a “reference case” projection for the most

likely development of Alaska's electricity sector is particularly challenging. Therefore, to develop an initial projection, simple assumptions were made, relying to the extent possible on widely-reviewed and accepted modeling assessments.

The reference case projections assume:

- Generation from plants in Alaska grows at 1.7 percent per year from 2006-2020, following growth rate in electricity sales.
- Generation from existing non-hydro plants is based on holding generation at 2005 levels. Generation from existing hydro-electric plants is assumed to be the same as the average generation from the last four years. New plants and changes to existing plants due to plant renovations and overhauls that result in higher capacity factors are counted as new generation.
- New power plants built between 2007 and 2020 will be dominated by renewable generation. 80 percent of new generation will be wind or hydroelectricity, with the remaining new generation supplied by natural gas (11 percent), coal (3 percent, upgrades to existing plants) and petroleum (6 percent). This mix is based on discussions with staff at Alaska Energy Authority (expecting that future fossil fuel generation could be limited by natural gas supply, mercury-restrictions for large coal plants, and overall economics of these plants compared to renewable generation), combined with the mix of existing non-renewable power plants.¹⁶

Summary of Assumptions and Reference Case Projections

As noted, projecting generation sources, sales, and emissions for the electric sector out to 2020 requires a number of key assumptions, including economic and demographic activity, changes in electricity-using technologies, regional markets for electricity (and competitiveness of various technologies and locations), access to transmission and distribution, the retirement of existing generation plants, the response to changing fuel prices, and the fuel/technology mix of new generation plants. The key assumptions described above are summarized in Table A4.

¹⁶ Personal communication Peter Crimp, Alaska Energy Authority, January 2007.
Alaska Department of
Environmental Conservation

Table A4. Key Assumptions and Methods for Electricity Projections for Alaska

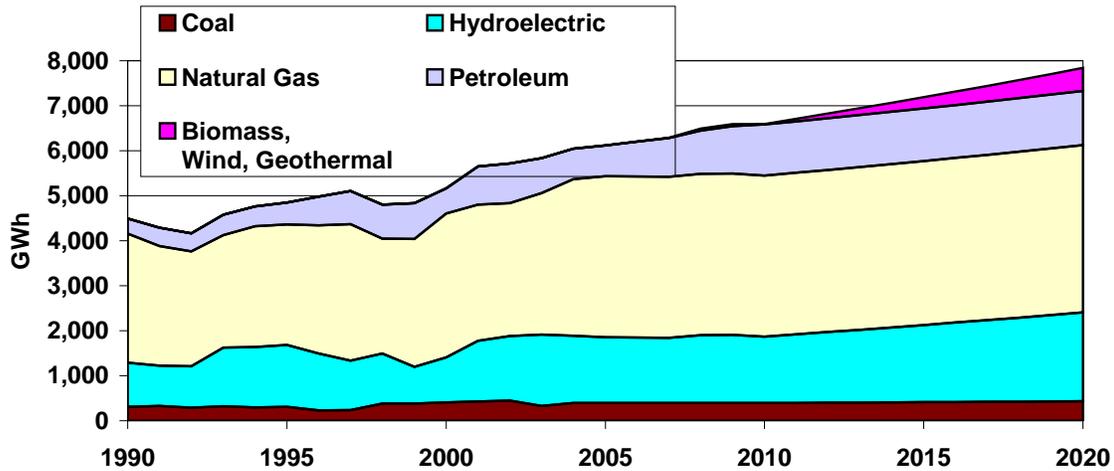
Electricity sales	Average annual growth of 1.7 percent from 2006 to 2020, based on extension of the 2000-2005 growth rate.
Electricity generation	1.7 percent per year from 2006-2020, based on consumption growth.
Transmission and Distribution losses	5 percent losses are assumed, based on average statewide losses, 1994-1997, (data from the US EPA Emission & Generation Resource Integrated Database ¹⁷)
New Generation Sources (2006-2020)	40% hydroelectric 40% wind 11% natural gas 6% coal 3% petroleum
Heat Rates	The assumed heat rates for new gas and coal generation are 7000 Btu/kWh and 9000 Btu/kWh, respectively, based on estimates used in similar analyses. ¹⁸
Operation of Existing Facilities	Existing non-hydro facilities are assumed to continue to operate as they were in 2005. Existing hydro facilities are assumed to generate 1,466 GWh per year the average generation over the period 2001-2005. Improvements in existing facilities that lead to higher capacity factor and more generation are captured under the new generation sources.

Figure A3 shows historical sources of electricity generation in the state by fuel source, along with projections to the year 2020 based on the assumptions described above. Based on the assumptions for new generation, Alaska’s electricity continues to be delivered from a mix of resources, with natural gas-fired generation accounting for the largest share (47% in 2020). Overall electricity generation grows at 1.7 percent per year from 2005 to 2020, with hydroelectric and wind generation having the greatest increases. Total renewable generation (hydro, wind, biomass and geothermal) account for 32% of total generation in 2020, following the above assumptions. Although no new biomass or geothermal generation are proposed in the reference case projections, this analysis includes generation from existing biomass co-generation plants and the new Chena Hot Springs geothermal plant.

¹⁷ <http://www.epa.gov/cleanenergy/egrid/index.htm>.

¹⁸ See, for instance, the Oregon Governor’s Advisory Group on Global Warming <http://egov.oregon.gov/ENERGY/GBLWRM/Strategy.shtml>.

Figure A3. Electricity Generated by Alaska Power Plants 1990-2020



Source: 1990-2005 EIA data, 2006-2020 CCS calculations based on assumptions described above, generation from petroleum resources is too small to be visible in the chart

GHG emission estimates were calculated by multiplying the energy consumption by the GHG emission factors for each type of fuel consumed. Energy consumption for 2006 to 2020 was calculated based on changes to future generation and the heat rate properties described in Table A4. The EPA SGIT software provided GHG emission factors by fuel for each state, consistent with factors used for EPA's national GHG inventory report.¹⁹ GHG emissions from geothermal plants were estimated using a rate of 7 Mt CO₂/GWh, based on estimates from the US EPA GHG inventory.²⁰

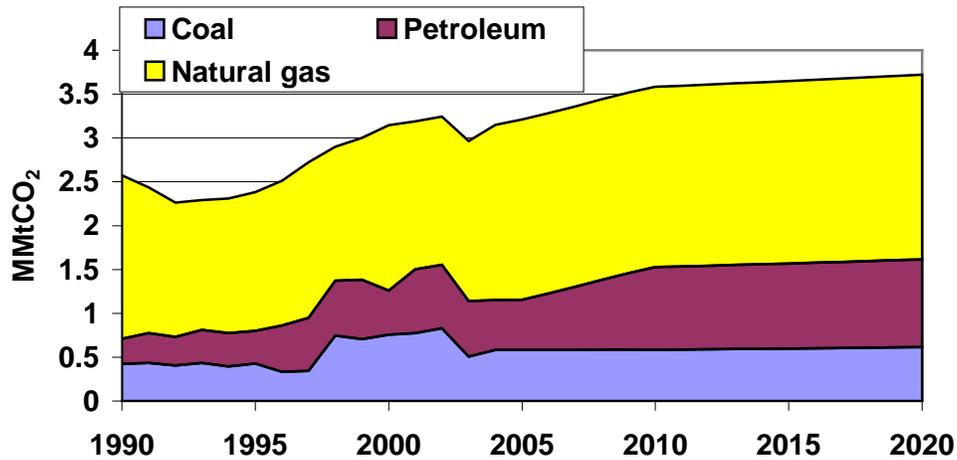
Figure A4 illustrates the GHG emissions associated with the mix of electricity generation shown in Figure A3. From 2005 to 2020, the emissions from Alaska electricity generation are projected to grow at 1.0 percent per year, lower than the growth in electricity generation because of the increased fraction of generation from renewables. As a result, the emission intensity (GHG emissions per MWh) of Alaska electricity is expected to decrease from 0.52 MtCO₂/MWh in 2004 to 0.48 MtCO₂/MWh in 2020.

Table A5 summarizes the GHG emissions for Alaska's electric sector from 1990 to 2020. During this time period, emissions are projected to increase by 45 percent. As mentioned at the beginning of this Appendix, the issue of whether to report GHG emissions based on the electricity consumed in the State (consumption-basis) or to report emissions based on the electricity produced in the State is a key question for many states. This is not important for Alaska because the GHG emission estimates are the same from either basis, since Alaska has very limited electricity imports. However, Table A5 reports the data in this manner to allow for simple comparisons with other state's GHG reports.

¹⁹ SGIT http://www.epa.gov/climatechange/emissions/state_guidance.html, National GHG Inventory, <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

²⁰ US EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, uses an emission factor of 2.05 Tg Carbon/QBTU.

Figure A4. Alaska GHG Emissions Associated with Electricity Production



Source: CCS calculations based on approach described in text.

Table A5. Alaska GHG Emissions from Electric Sector, 1990-2020.

(Million Metric Tons CO ₂ e)	1990	2000	2005	2010	2020
Electricity Production	2.6	3.1	3.2	3.6	3.7
Coal	0.4	0.8	0.6	0.6	0.6
CO ₂	0.4	0.8	0.6	0.6	0.6
CH ₄ and N ₂ O	0.0	0.0	0.0	0.0	0.0
Natural Gas	1.9	1.9	2.1	2.1	2.1
CO ₂	1.9	1.9	2.1	2.1	2.1
CH ₄ and N ₂ O	0.0	0.0	0.0	0.0	0.0
Petroleum	0.3	0.5	0.6	0.9	1.0
CO ₂	0.3	0.5	0.6	0.9	1.0
CH ₄ and N ₂ O	0.0	0.0	0.0	0.0	0.0
Geothermal, Biomass and Waste (CO ₂ , CH ₄ and N ₂ O)	0.0	0.0	0.0	0.0	0.0
Electricity Exports	0.0	0.0	0.0	0.0	0.0
Electricity Consumption	2.6	3.1	3.2	3.6	3.7

Note: Values that are less than 0.05 MMtCO₂e are listed as 0.0 in Table A5.

Because Alaska has very limited electricity imports or exports, the GHG emissions on a production-basis are the same as GHG emissions on a consumption-basis.

Appendix B. Residential, Commercial, and Industrial Fossil Fuel Combustion

Overview

Activities in the RCI²¹ sectors produce carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions when fuels are combusted to provide space heating, process heating, and other applications. Carbon dioxide accounts for over 99% of these emissions on a million metric tons (MMt) of CO₂ equivalent (CO₂e) basis in Alaska. In addition, since these sectors consume electricity, one can also attribute emissions associated with electricity generation to these sectors in proportion to their electricity use.²² If emissions from the generation of the electricity they consume are not included, the RCI sectors are between them the largest source of gross greenhouse gas (GHG) emissions in Alaska. Direct use of oil, natural gas, coal, and wood in the RCI sectors accounted for an estimated 25.5 MMtCO₂e of gross GHG emissions in 2005.²³

Emissions and Reference Case Projections

Emissions for direct fuel use were estimated using the United States Environmental Protection Agency's (US EPA's) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for RCI fossil fuel combustion.²⁴ The default data used in SGIT for Alaska are from the United States Department of Energy (US DOE) Energy Information Administration's (EIA's) *State Energy Data* (SED). The SGIT default data for Alaska were revised using the most recent data available, which includes: (1) 2002 SED information for all fuel types;²⁵ (2) 2003 SED information for coal, and wood and wood waste;²⁶ (3) 2004 SED information for natural gas;⁶ (4) 2003 and 2004 SED information for petroleum (distillate oil, kerosene and liquefied petroleum gas) consumption;⁶ (5) 2004 electricity consumption data from the EIA's *State Electricity Profiles*;²⁷ and (6) 2005 natural gas consumption data from the EIA's *Natural Gas Navigator*.²⁸

Note that the EIIP methods for the industrial sector exclude from CO₂ emission estimates the amount of carbon that is stored in products produced from fossil fuels for non-energy uses. For

²¹ The industrial sector includes emissions associated with agricultural energy use and fuel used by the fossil fuel production industry.

²² One could similarly allocate GHG emissions from natural gas transmission and distribution, other fuels production, and transport-related GHG sources to the RCI sectors based on their direct use of gas and other fuels, but we have not done so here due to the relatively small level of emissions from these sources.

²³ Emissions estimates from wood combustion include only N₂O and CH₄. Carbon dioxide emissions from biomass combustion are assumed to be "net zero", consistent with US EPA and IPCC methodologies, and any net loss of carbon stocks due to biomass fuel use should be accounted for in the forestry analysis.

²⁴ GHG emissions were calculated using SGIT, with reference to *EIIP, Volume VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels"*, August 2004; and Chapter 2 "Methods for Estimating Methane and Nitrous Oxide Emissions from Stationary Combustion", August 2004.

²⁵ EIA *State Energy Data 2002*, Data through 2002, released June 30, 2006, (http://www.eia.doe.gov/emeu/states/state.html?q_state_a=co&q_state=ALASKA).

²⁶ EIA *State Energy Data 2003 revisions for all fuels and first release of 2004 information for natural gas and petroleum*, (http://www.eia.doe.gov/emeu/states/seds_updates.html).

²⁷ EIA *Electric Power Annual 2005 - State Data Tables*, (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html).

²⁸ EIA *Natural Gas Navigator* (http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcua_SAK_a.htm).

example, the methods account for carbon stored in petrochemical feedstocks, and liquefied petroleum gas (LPG), and natural gas used as feedstocks by chemical manufacturing plants (i.e., not used as fuel), as well as carbon stored in asphalt and road oil produced from petroleum. The carbon storage assumptions for these products are explained in detail in the EIIP guidance document.²⁹ The fossil fuel categories for which the EIIP methods are applied in the SGIT software to account for carbon storage include the following categories: asphalt and road oil, coking coal, distillate fuel, feedstocks (naphtha with a boiling point of less than 401 degrees Fahrenheit), feedstocks (other oils with boiling points greater than 401 degrees Fahrenheit), LPG, lubricants, miscellaneous petroleum products, natural gas, pentanes plus,³⁰ petroleum coke, residual fuel, still gas, and waxes. Data on annual consumption of the fuels in these categories as chemical industry feedstocks were obtained from the EIA SED.

Reference case emissions from direct fuel combustion were estimated based on fuel consumption forecasts from EIA's *Annual Energy Outlook 2006* (AEO2006),³¹ with adjustments for Alaska's projected population³² and employment growth. Alaska employment data for the manufacturing (goods producing) and non-manufacturing (commercial or services providing) sectors were obtained from the Alaska Department of Labor and Workforce Development.³³ Regional employment data for the same sectors were obtained from EIA for the EIA's Pacific region.³⁴ Table B1 shows historic and projected growth rates for electricity sales by sector. Table B2 shows historic and projected growth rates for energy use by sector and fuel type.

For the residential sector, the rate of population growth is expected to increase by about 0.52% annually between 2004 and 2020; this demographic trend is reflected in the growth rates for residential fuel consumption. Based on the Alaska Department of Labor and Workforce Development's forecast (2004 to 2014), commercial and industrial employment are projected to increase at compound annual rates of 1.09% and 0.95%, respectively, and these growth rates are reflected in the growth rates in energy use shown in Table B2 for the two sectors. These estimates of growth relative to population and employment reflect expected responses of the

²⁹ EIIP, Volume VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.

³⁰ A mixture of hydrocarbons, mostly pentanes and heavier fractions, extracted from natural gas.

³¹ EIA AEO2006 with Projections to 2030, (<http://www.eia.doe.gov/oiaf/aeo/index.html>).

³² Population data from the Alaska Department of Labor and Workforce Development, "Workforce Information," Home (<http://almis.labor.state.ak.us/>), Population & Census, Estimates & Projections, Population Data Tables. Data for 1990 through 2000 found in "Alaska Population Estimates 2000-2005," under Historical Estimates (at bottom of page), Select "Borough and Census Area 1990-2000," in Excel file named "02T2-1a.xls." Data for 2001 through 2005 found in "Alaska Population Estimates 2000-2006," under Vintage 2005 Estimates, Borough, and Census Area Estimates, "Population by Labor Market Area, Borough and Census Area, and Components of Change, 1990-2005" in Excel file named "05t2-1.xls." Data for 2006 through 2029 found in "Alaska Population Projections (2005-2029)," under "February 2005 issue of Alaska Economic Trends," in PDF file named "feb05.pdf" (Projections for Alaska population 2005-2029, Table 5. Population Growth Projections Alaska 2005-2029, Medium Population Values in Table 5 used for forecast).

³³ Alaska Department of Labor and Workforce Development, "Workforce Information," Home (<http://almis.labor.state.ak.us/>), Industry Forecasts, Under Ten-Year Industry Employment Forecasts, Ten-year industry employment forecasts for Alaska published in the November 2006 issue of Alaska Economic Trends (extracted data from file named "nov06ind.pdf").

³⁴ AEO2006 employment projections for EIA's Pacific region obtained through special request from EIA (dated September 27, 2006).

economy — as simulated by the EIA’s National Energy Modeling System — to changing fuel and electricity prices and changing technologies, as well as to structural changes within each sector (such as shifts in subsectoral shares and in energy use patterns).

Table B1. Electricity Sales Annual Growth Rates, Historical and Projected

Sector	1990-2004 ^a	2004-2020 ^b
Residential	1.6%	2.1%
Commercial	2.0%	1.5%
Industrial	6.6%	1.7%
Total	2.2%	1.7%

^a 1990-2004 compound annual growth rates calculated from Alaska electricity sales by year from EIA state electricity profiles (Table 8), (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html).

^b 2004-2020 compound annual growth rate for total for all three sectors taken from forecast for the energy supply sector (see Appendix A).

Table B2. Historic and Projected Average Annual Growth in Energy Use in Alaska, by Sector and Fuel, 1990-2020

	1990-2004 ^a	2005-2010 ^b	2010-2015 ^b	2015-2020 ^b
Residential				
natural gas	2.1%	0.7%	0.7%	0.3%
petroleum	0.2%	0.6%	-0.3%	1.4%
wood	4.4%	0.6%	-0.1%	0.0%
coal	-4.1%	0.6%	-1.0%	-1.1%
Commercial				
natural gas	-1.2%	-0.3%	1.8%	1.2%
petroleum	0.6%	-0.9%	0.6%	0.2%
wood	8.8%	-0.4%	0.1%	-0.3%
coal	-0.2%	-0.6%	0.1%	-0.3%
Industrial				
natural gas	2.3%	1.4%	2.0%	2.3%
petroleum	2.2%	3.2%	1.7%	1.1%
wood	-28.8%	3.4%	2.7%	2.6%
coal	-13.9%	2.4%	0.4%	0.9%

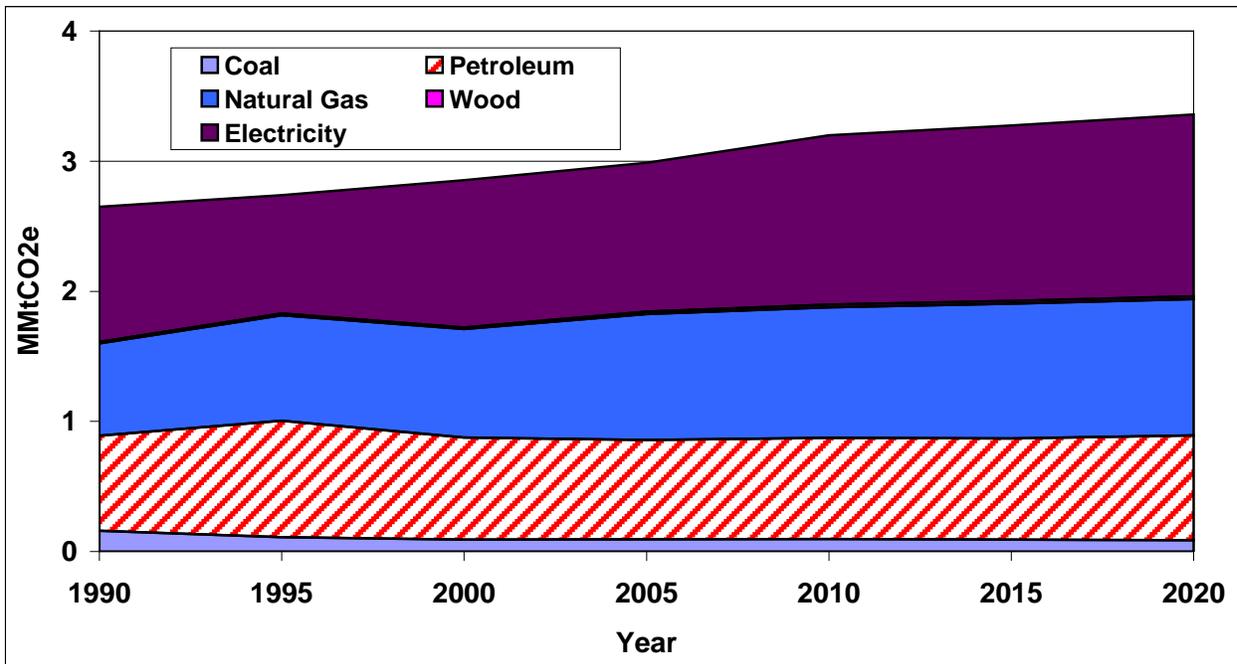
^a Compound annual growth rates calculated from EIA SED historical consumption by sector and fuel type for Alaska. Latest year for which EIA SED information was available for each fuel type is 2003 for coal and wood/wood waste, 2004 for petroleum (distillate oil, kerosene, and LPG), and 2005 for natural gas. Petroleum includes distillate fuel, kerosene, and LPG for all sectors plus residual oil for the commercial and industrial sectors. Industrial coal consumption for 1990 through 2002 was zero; growth rate for industrial coal is calculated from EIA SED consumption reported for 1993 through 2003.

^b Figures for growth periods starting after 2004 are calculated from AEO2006 projections for EIA’s Pacific region, adjusted for Alaska’s projected population for the residential sector, non-manufacturing employment for the commercial sector, and manufacturing employment for the industrial sector.

Results

Figures B1, B2, and B3 show historic and projected emissions for the RCI sectors in Alaska from 1990 through 2020. These figures show the emissions associated with the direct consumption of fossil fuels and, for comparison purposes, show the share of emissions associated with the generation of electricity consumed by each sector. The residential sector’s share of total RCI emissions from direct fuel use and electricity use was 12% in 1990, declined to 10% in 2005, and is projected to decline to 9% by 2020. The commercial sector’s share of total RCI emissions from direct fuel use and electricity use was 15% in 1990, increased to a high of 15% in 2000, declined to 12% in 2005, and is projected to decline to 10% by 2020. The industrial sector’s share of total RCI emissions from direct fuel use and electricity was 73% in 1990, increased to 78% in 2005, and is projected to increase to 81% by 2020.

Figure B1. Residential Sector GHG Emissions from Fuel Consumption



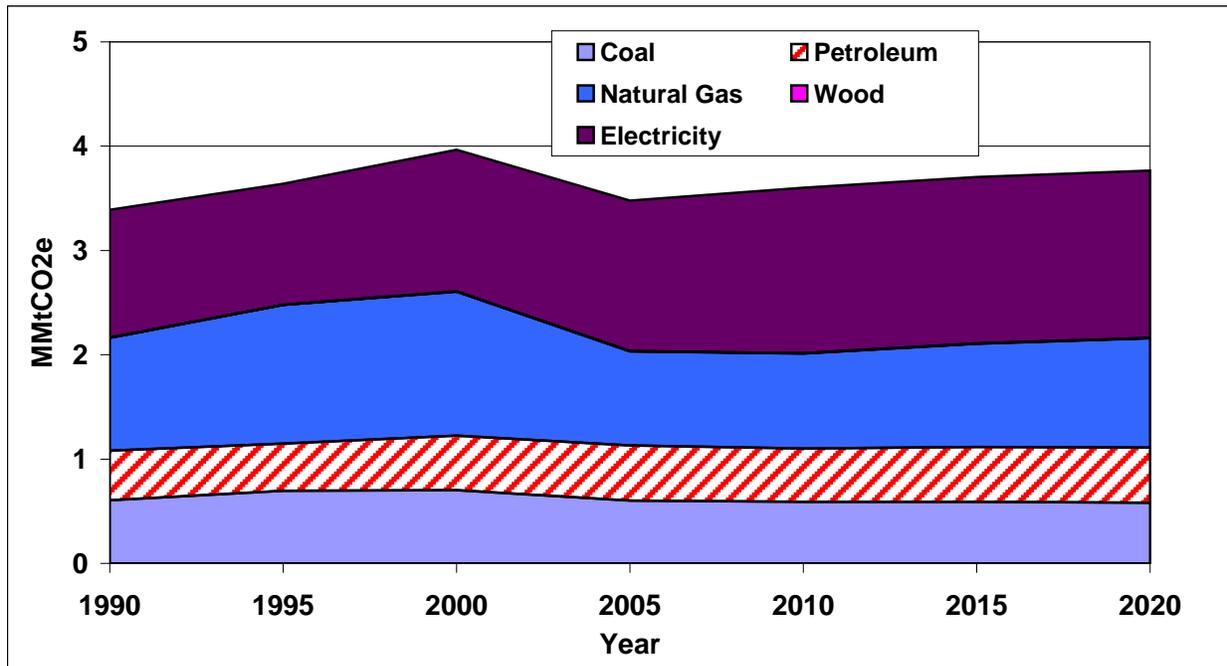
Note: Emissions associated with wood combustion are too small to be seen on this graph.

For the residential sector, emissions from electricity and direct fossil fuel use in 1990 were about 2.6 MMtCO₂e, and are estimated to increase to about 3.4 MMtCO₂e by 2020. Emissions associated with the generation of electricity to meet residential energy consumption demand accounted for about 39% of total residential emissions in 1990 and are estimated to increase to 42% of total residential emissions by 2020. In 1990, natural gas consumption accounted for about 27% of total residential emissions and is estimated to account for about 31% of total residential emissions by 2020. Residential-sector emissions associated with the use of petroleum accounted for about 28% of total residential emissions in 1990 and are estimated to decline to 24% of total residential emissions by 2020. Residential-sector emissions associated with the use of coal and wood in 1990 were about 0.17 MMtCO₂e combined, and accounted for about 6.5% of total residential emissions. By 2020, emissions associated with the consumption of these two

fuels are estimated to be 0.11 MMtCO₂e and to account for 3.2% of total residential sector emissions.

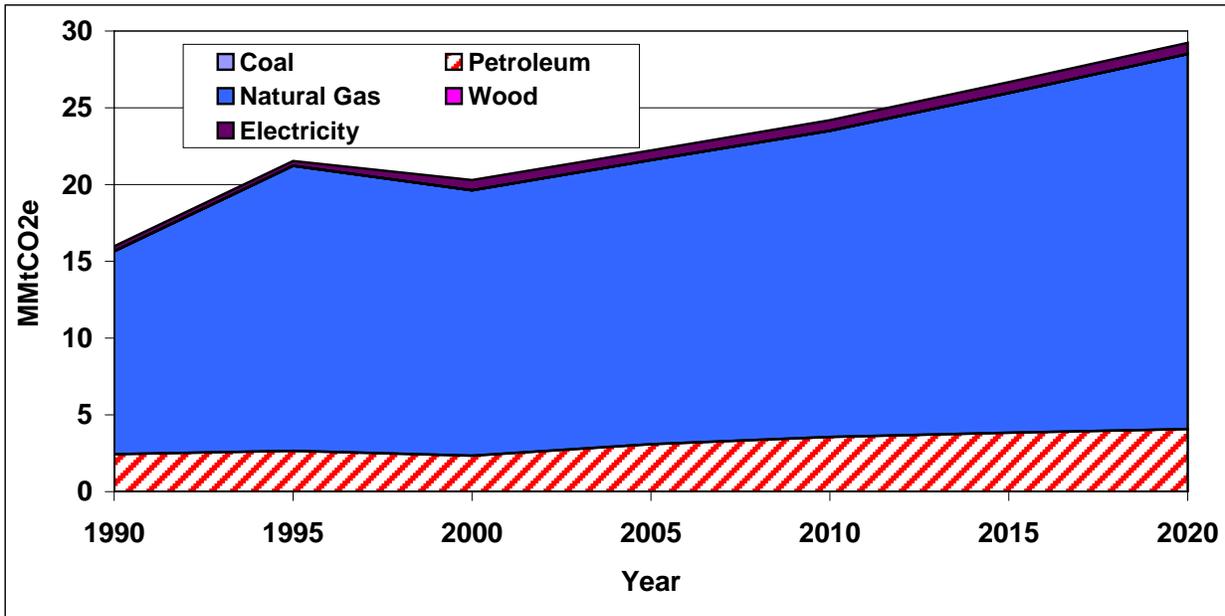
For the 15-year period 2005 to 2020, residential-sector GHG emissions associated with the use of electricity, natural gas, and petroleum are expected to increase at average annual rates of about 1.4%, 0.5%, and 0.4%, respectively. Emissions associated with the use of wood are expected to increase annually by about 0.1%, and emissions associated with the use of coal are expected to decline by about -0.6% annually. Total GHG emissions for this sector increase by an average of about 0.8% annually over the 15-year period.

Figure B2. Commercial Sector GHG Emissions from Fuel Consumption



Note: Emissions associated with wood combustion too small to be seen on this graph.

Figure B3. Industrial Sector GHG Emissions from Fuel Consumption



Note: emissions for wood and coal combustion are too small to show up in this graph.

For the commercial sector, emissions from electricity and direct fuel use in 1990 were about 3.4 MMtCO₂e and are estimated to increase to about 3.8 MMtCO₂e by 2020. Emissions associated with the generation of electricity to meet commercial energy consumption demand accounted for about 36% of total commercial emissions in 1990, and are estimated to increase to about 43% of total commercial emissions by 2020. In 1990, natural gas consumption accounted for about 32% of total commercial emissions, and is estimated to account for about 28% of total commercial emissions by 2020. Commercial-sector emissions associated with the use of coal accounted for about 18% of total commercial emissions in 1990, and are estimated to decline to about 16% of total commercial emissions by 2020. Commercial-sector emissions associated with the use of petroleum accounted for about 14% of total commercial emissions in 1990, and are projected to remain at about 14% of total commercial emissions by 2020. Commercial-sector emissions associated with the use of wood accounted for about 0.04% of total commercial emissions from 1990, and are projected to be at about 0.1% of total commercial emissions by 2020.

For the 15-year period 2005 to 2020, commercial-sector GHG emissions associated with the use of electricity, natural gas, and petroleum are expected to increase at average annual rates of about 0.7%, 1.0%, and 0.03%, respectively. Emissions associated with the use of coal and wood are expected to decline annually by about -0.23% and -0.20%, respectively. Total GHG emissions for this sector increase by an average of about 0.53% annually over the 15-year period.

For the industrial sector, emissions in 1990 were about 16 MMtCO₂e, and are estimated to increase to about 29 MMtCO₂e by 2020. Emissions associated with the generation of electricity to meet industrial energy consumption demand accounted for about 2% of total industrial emissions in 1990 and are estimated to increase to about 2.5% of total industrial emissions by

2020. In 1990, natural gas consumption accounted for about 83% of total industrial emissions and is estimated to account for about 84% of total industrial emissions by 2020. Industrial-sector emissions associated with the use of petroleum accounted for about 15% of total industrial sector emissions in 1990, and are projected to decline slightly to about 14% of total industrial emissions by 2020. Industrial-sector emissions associated with the use of coal and wood in 1990 were about 0.01 MMtCO₂e combined and accounted for about 0.07% of total industrial emissions. For 2020, emissions associated with the consumption of these fuels are estimated to be 0.001 MMtCO₂e and to account for 0.004% of total industrial sector emissions.

For the 15-year period 2005 to 2020, industrial sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 0.96% and 1.9%, respectively. Emissions associated with the use of coal, petroleum, and wood are expected to increase annually by about 1.1%, 1.9%, and 2.9%, respectively. Total GHG emissions for this sector increase by an average of about 1.8% annually over the 15-year period.

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

- Population and economic growth are the principal drivers for electricity and fuel use. The reference case projections are based on regional fuel consumption projections for EIA's Pacific modeling region scaled for Alaska population and employment growth projections. Consequently, there are significant uncertainties associated with the projections. Future work should attempt to base projections of GHG emissions on fuel consumption estimates specific to Alaska to the extent that such data become available.
- The AEO2006 projections assume no large long-term changes in relative fuel and electricity prices, relative to current price levels and to US DOE projections for fuel prices. Price changes would influence consumption levels and, to the extent that price trends for competing fuels differ, may encourage switching among fuels. These projections result in a 32% increase in GHG emissions for fossil fuel consumption, while the fossil fuel fugitive emissions (see Appendix E) are projected to decline during the forecast period. On the other hand, it is expected that natural gas consumption per volume of fuel produced will increase as mature production fields decline and the energy needed to extract oil and gas increases. Additional work should be done to identify Alaska-specific industrial fossil fuel forecast data.
- Work with stakeholder groups in other states with a significant fossil fuel industry has indicated that the EIA data for fuel consumption in the fossil fuel industry are not always well represented. Additional work in this area is warranted in Alaska.

Appendix C. Transportation Energy Use

Overview

The transportation sector is one of the largest sources of GHG emissions in Alaska – accounting for 39% of Alaska’s gross GHG emissions in 2000. Carbon dioxide accounts for about 98% of transportation GHG emissions from fuel use. Most of the remaining GHG emissions from the transportation sector are due to N₂O emissions from gasoline and jet engines.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2002 were estimated using SGIT and the methods provided in the EIIP guidance document for the sector.^{35,36} For onroad vehicles, the CO₂ emission factors are in units of lb/MMBtu and the CH₄ and N₂O emission factors are both in units of grams/VMT. Key assumptions in this analysis are listed in Table C1. The default data within SGIT were used to estimate emissions, with the most recently available fuel consumption data (2002) from EIA SED added.³⁷ The default VMT data in SGIT were replaced with state-level annual VMT from Alaska Department of Transportation and Public Facilities (ADOT&PF).³⁸ State-level VMT was allocated to vehicle types using the default vehicle mix data in SGIT.

Onroad gasoline and diesel emissions were projected based on VMT projections from the WRAP mobile source inventory³⁹ and growth rates developed from national vehicle type VMT forecasts reported in EIA’s *Annual Energy Outlook 2006* (AEO 2006). The VMT projections taken from the WRAP inventory show an average annual growth rate in total state VMT of 1.3%. The AEO2006 data were incorporated because they indicate significantly different VMT growth rates for certain vehicle types (e.g., 34 percent growth between 2002 and 2020 in heavy-duty gasoline vehicle VMT versus 284 percent growth in light-duty diesel truck VMT over this period). The procedure first applied the AEO2006 vehicle type-based national growth rates to 2002 Alaska estimates of VMT by vehicle type. These data were then used to calculate the estimated proportion of total VMT by vehicle type in each year. Next, these proportions were applied to the projected state-total VMT for each year to yield the vehicle-type compound annual average growth rates are displayed in Tables C2.

³⁵ CO₂ emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 1. “Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels”, August 2004.

³⁶ CH₄ and N₂O emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 3. “Methods for Estimating Methane and Nitrous Oxide Emissions from Mobile Combustion”, August 2004.

³⁷ Energy Information Administration, State Energy Consumption, Price, and Expenditure Estimates (SED), <http://www.eia.doe.gov/emeu/states/seds.html>

³⁸ David Phillips, Research Analyst, Alaska Department of Transportation & Public Facilities

³⁹ WRAP Mobile Source Emission Inventories Update, Western Regional Air Partnership,

<http://www.wrapair.org/forums/ef/UMSI/index.html>

Table C1. Key Assumptions and Methods for the Transportation Inventory and Projections

Vehicle Type and Pollutants	Methods
<p>Onroad gasoline, diesel, natural gas, and LPG vehicles – CO₂</p>	<p>Inventory (1990 – 2002) EPA SGIT and fuel consumption from EIA SED</p> <p>Reference Case Projections (2003 – 2020) Gasoline and diesel fuel projected using VMT projections the WRAP, adjusted by fuel efficiency improvement projections from AEO2006. Other onroad fuels projected using Pacific Region fuel consumption projections from EIA AEO2006 adjusted using state-to-regional ratio of population growth.</p>
<p>Onroad gasoline and diesel vehicles – CH₄ and N₂O</p>	<p>Inventory (1990 – 2002) EPA SGIT, onroad vehicle CH₄ and N₂O emission factors by vehicle type and technology type within SGIT were updated to the latest factors used in the U.S. EPA’s <i>Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003</i>.</p> <p>State total VMT replaced with VMT provided by ADOT&PF, VMT allocated to vehicle types using default data in SGIT.</p> <p>Reference Case Projections (2003 – 2020) VMT projections from WRAP.</p>
<p>Non-highway fuel consumption (jet aircraft, gasoline-fueled piston aircraft, boats, locomotives) – CO₂, CH₄ and N₂O</p>	<p>Inventory (1990 – 2002) EPA SGIT and fuel consumption from EIA SED. Commercial marine fuel consumption estimates from DEC and Corbett inventories and allocation from national fuel consumption estimates.</p> <p>Reference Case Projections (2003 – 2020) Aircraft projected using aircraft operations projections from FAA and jet fuel efficiency improvement projections from AEO2006. Commercial marine projected using growth factors from ADEC inventory.</p>

Table C2. Alaska Vehicle Miles Traveled Compound Annual Growth Rates

Vehicle Type	2002-2005	2005-2010	2010-2015	2015-2020
Heavy Duty Diesel Vehicle	3.39%	2.49%	2.20%	2.16%
Heavy Duty Gasoline Vehicle	2.10%	0.98%	1.65%	1.73%
Light Duty Diesel Truck	4.87%	6.01%	6.02%	6.23%
Light Duty Diesel Vehicle	4.87%	6.01%	6.02%	6.23%
Light Duty Gasoline Truck	0.70%	1.06%	1.05%	1.01%
Light Duty Gasoline Vehicle	0.70%	1.06%	1.05%	1.01%
Motorcycle	0.70%	1.06%	1.05%	1.01%

Onroad gasoline and diesel fuel consumption was forecasted by developing a set of growth factors that adjusted the VMT projections to account for improvements in fuel efficiency. Fuel efficiency projections were taken from AEO2006. These projections suggest onroad fuel consumption growth rates of 0.2% per year for gasoline and 2.5% per year for diesel between 2002 and 2020.

Gasoline consumption estimates for 1990-2002 were adjusted by subtracting ethanol consumption. While the historical ethanol consumption suggests continued growth, projections for ethanol consumption in Alaska were not available. Therefore, ethanol consumption was assumed to remain at the 2002 level (1.7% of total gasoline) in the reference case projections. Biodiesel and other biofuel consumption were not considered in this inventory because historical and projection data were not available.

For the aircraft sector, emission estimates for 1990 to 2002 are based on SGIT methods and fuel consumption from EIA. Emissions for jet fuel were projected from 2002 to 2005 using historical jet fuel prime supplier sales volumes in Alaska for 2002-2005 from EIA.⁴⁰ Prime supplier sales volumes for aviation gasoline were not available for 2002-2005; therefore, emissions were projected from 2002-2005 using the FAA data described below. CCS reviewed a criteria pollutant emissions inventory on Alaska aviation prepared under a WRAP-sponsored study⁴¹; however no fuel consumption estimates were prepared in that project (activity data were in terms of landings and take-offs).

State-level fuel consumption projections for aviation fuels are not available; therefore, jet fuel and aviation gasoline emissions were projected from 2005-2020 using 2006-2020 aircraft operations forecasts from the Federal Aviation Administration's Terminal Area Forecast System (TAF).⁴² A base-year of 2006 was used because the TAF data for 2002-2005 were developed using a different scenario and were not consistent with the 2006-2020 data. The growth rate from 2005 to 2006 was assumed to be the same as the 2006-2010 average annual growth rate. Jet fuel emissions were projected using the sum of itinerant aircraft operations from air carrier, air taxi/commuter, general aviation, and military aircraft. The post-2005 commercial aircraft

⁴⁰ Alaska Prime Supplier Sales Volumes of Petroleum Products, Energy Information Administration, http://tonto.eia.doe.gov/dnav/pet/xls/pet_cons_prim_dcu_SAK_a.xls.

⁴¹ *Alaska Aviation Emission Inventory*, Sierra Research, June 14, 2005.

⁴² Terminal Area Forecast, Federal Aviation Administration, <http://www.apo.data.faa.gov/main/taf.asp>.

estimates were adjusted to reflect the projected increase in national aircraft fuel efficiency (indicated by increased number of seat miles per gallon), as reported in AEO2006. General aviation emissions were projected based on local general aviation aircraft operations forecasts. For aviation gasoline, the 2005-2010 annual growth rate was applied to 2002-2005. These projections resulted in the compound annual growth rates shown in Table C3.

Table C3. Alaska Jet Fuel and Aviation Gasoline Compound Annual Growth Rates

Vehicle Type	2002-2005	2005-2010	2010-2015	2015-2020
Jet Fuel	4.86%	0.04%	-0.24%	-0.39%
Aviation Gasoline	0.24%	0.24%	0.25%	0.27%

Commercial marine fuel consumption was estimated using activity data and brake-specific fuel consumption factors (in units of gallons/kW-hr) from the commercial marine criteria pollutant inventory recently developed for ADEC.⁴³ This inventory covers nine major ports in Alaska. Fuel consumption for the remaining ports was developed by allocating 1990-2004 national diesel and residual oil vessel bunkering fuel consumption estimates obtained from EIA.⁴⁴ Marine vessel fuel consumption was allocated to each area using the marine vessel activity allocation methods/data compiled to support the development of EPA’s National Emissions Inventory (NEI).⁴⁵ In keeping with the NEI, 75 percent of each year’s distillate fuel and 25 percent of each year’s residual fuel were assumed to be consumed within the port area (remaining consumption is assumed to occur while ships are underway). National port area fuel consumption was allocated to these areas based on year-specific freight tonnage data reported in “Waterborne Commerce in the United States Waterways and Harbors”.⁴⁶ Freight tonnage for the nine major ports covered by the ADEC inventory was subtracted from the state total freight tonnage to give the remainder. Offshore CO₂ emissions and fuel consumption for the Alaska’s exclusive economic zone (EEZ) were taken from a study by Corbett for the Commission for Environmental Cooperation in North America (CEC).⁴⁷ 2002 fuel consumption from the ADEC and CEC inventories were scaled to other years using freight tonnage data. Emissions were then estimated from fuel consumption estimates using SGIT emissions factors for marine diesel and residual fuels. Emissions were projected using growth factors from the ADEC inventory.

For rail and marine gasoline, 1990 – 2004 estimates are based on SGIT methods and fuel consumption from EIA. For rail, the historic data show no significant positive or negative trend; therefore, no growth was assumed for this sector. Marine gasoline projections were based on the

⁴³ Commercial Marine Inventories for Select Alaskan Ports, prepared by E.H. Pechan & Associates, prepared for the Alaska Department of Environmental Conservation, June, 2005.

⁴⁴ U.S. Department of Energy, Energy Information Administration, “Petroleum Navigator” (diesel data obtained from <http://tonto.eia.doe.gov/dnav/pet/hist/kd0vabnus1a.htm>; residual data obtained from <http://tonto.eia.doe.gov/dnav/pet/hist/kprvatnus1a.htm>).

⁴⁵ See methods described in ftp://ftp.epa.gov/EmisInventory/2002finalnei/documentation/mobile/2002nei_mobile_nonroad_methods.pdf

⁴⁶ Waterborne Commerce Statistics Center, <http://www.iwr.usace.army.mil/ndc/wcsc/wcsc.htm>.

⁴⁷ Estimate, Validation, and Forecasts of Regional Commercial Marine Vessel Inventories, submitted by J. Corbett, prepared for the California Air Resources Board, California Environmental Protection Agency, and Commission for Environmental Cooperation in North America, <http://coast.cms.udel.edu/NorthAmericanSTEEM/>.

1994-2004 historical trend. Marine gasoline consumption estimates for 1990-1993 were significantly higher than subsequent years; therefore, these years were not included in the trend analysis.

Fuel consumption data from EIA includes nonroad gasoline and diesel fuel consumption in the commercial and industrial sectors. Therefore, nonroad emissions are included in the RCI emissions in this inventory (see Appendix B). Table C2 shows how EIA divides gasoline and diesel fuel consumption between the transportation, commercial, and industrial sectors.

Table C2. EIA Classification of Gasoline and Diesel Consumption

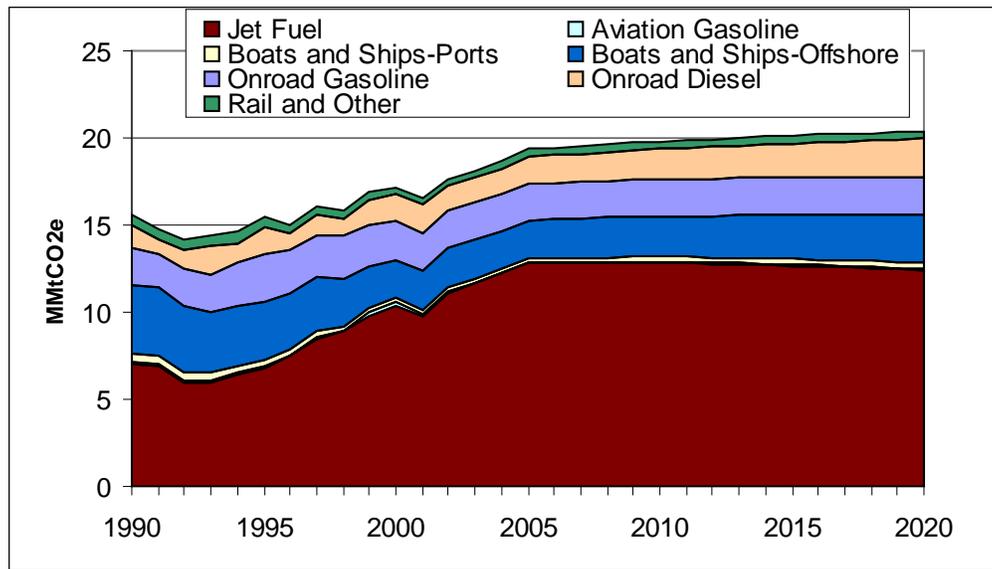
Sector	Gasoline Consumption	Diesel Consumption
Transportation	Highway vehicles, marine	Vessel bunkering, military use, railroad, highway vehicles
Commercial	Public non-highway, miscellaneous use	Commercial use for space heating, water heating, and cooking
Industrial	Agricultural use, construction, industrial and commercial use	Industrial use, agricultural use, oil company use, off-highway vehicles

Results

As shown in Figure C1, jet fuel consumption accounts for the largest share of transportation GHG emissions. Emissions from jet fuel consumption increased by about 59% from 1990-2002 to cover almost 63% of total transportation emissions in 2002. GHG emissions from marine fuel consumption decreased by 43% from 1990 to 2002, and in 2002 accounted for 14% of GHG emissions from the transportation sector. Emissions from onroad gasoline grew by only 1% between 1990 and 2002 and onroad diesel grew by 8% during this period. In 2002, onroad gasoline and diesel accounted for 12% and 8% of total transportation emissions, respectively. Emissions from all other categories combined (aviation gasoline, locomotives, natural gas and LPG, and oxidation of lubricants) contributed slightly over 2% of total transportation emissions in 2002.

GHG emissions from jet fuel are projected to increase by 12% between 2002 and 2020. Emissions from boats and ships are projected to increase by 21% during this period. Onroad gasoline consumption are projected to increase by about 3%, and emissions from onroad diesel consumption are expected to increase by 57% between 2002 and 2020.

Figure C1. Transportation GHG Emissions by Fuel, 1990-2020



Key Uncertainties

Projections of Vehicle Miles of Travel (VMT) and Biofuels Consumption

One source of uncertainty is the future year vehicle mix, which was calculated based on national growth rates for specific vehicle types. These growth rates may not reflect vehicle-specific VMT growth rates for the state. Also, onroad gasoline and diesel growth rates may be slightly overestimated because increased consumption of biofuels between 2005 and 2020 was not taken into account (due to a lack of data).

Uncertainties in Aviation Fuel Consumption

The consumption of international bunker fuels included in jet fuel consumption from EIA is another uncertainty. This fuel consumption associated with international air flights should not be included in the state inventory (as much of it is actually consumed out of state); however, data were not available to subtract this consumption from total jet fuel estimates. Another uncertainty associated with aviation emissions is the use of national seat miles per gallon data to adjust for increases in commercial aircraft fuel efficiency. There is a significant fraction of cargo activity in the commercial aircraft sector in Alaska. The current FAA forecasts indicate little growth in the future; however surveys with Alaskan passenger and cargo carriers are warranted.

Commercial Marine Vessels

In order to provide complete coverage of fuel consumption in this sector (in port as well as underway emissions within 200 miles of shore), several different sources of information had to be compiled. In particular, use of the EPA NEI methods for allocating distillate and residual fuel consumption for in-port and underway activity could result in overlaps with the data for underway emissions from the Corbett et al study cited above. Additional work to investigate this issue could result in improved emission estimates.

Appendix D. Industrial Processes

Overview

Emissions in the industrial processes category span a wide range of activities, and reflect non-combustion sources of greenhouse gas (GHG) emissions from several industrial processes. The industrial processes that exist in Alaska, and for which emissions are estimated in this inventory, include the following:

- Carbon Dioxide (CO₂) from consumption of limestone, dolomite, and soda ash;
- SF₆ from transformers used in electric power transmission and distribution (T&D) systems; and
- HFCs and PFCs from consumption of substitutes for ozone-depleting substances (ODS) used in cooling and refrigeration equipment.

Other industrial processes that are sources of GHG emissions but are not found in Alaska include the following:

- Carbon Dioxide (CO₂) from production of cement, lime, and soda ash;
- Nitrous oxide (N₂O) from nitric and adipic acid production;
- Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆) from semiconductor manufacture;
- PFCs from aluminum production;
- HFCs from HCFC-22 production; and
- SF₆ from magnesium production and processing.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2005 were estimated using the State Greenhouse Gas Inventory Tool (SGIT) and the methods provided in the Emissions Inventory Improvement Project (EIIP) guidance document for this sector.⁴⁸ Table D1 identifies for each emissions source category the information needed for input into SGIT to calculate emissions, the data sources used, and the historical years for which emissions were calculated based on the availability of data. Table D2 lists the data sources used to quantify activities related to industrial process emissions, the annual compound growth rates implied by estimates of future activity used, and the years for which the reference case projections were calculated.

⁴⁸ GHG emissions were calculated using SGIT, with reference to the Emission Inventory Improvement Program, Volume VIII: Chapter. 6. "Methods for Estimating Non-Energy Greenhouse Gas Emissions from Industrial Processes", August 2004. This document is referred to as "EIIP" below.

Table D1. Approach to Estimating Historical Emissions

Source Category	Time Period	Required Data for SGIT	Data Source
Limestone and Dolomite Consumption	1994 - 2002	Consumption of limestone and dolomite by industrial sectors.	For default data, the state's total limestone consumption (as reported by USGS) is multiplied by the ratio of national limestone consumption for industrial uses to total national limestone consumption. Additional information on these calculations, including a definition of industrial uses, is available in Chapter 6 of the EIIIP guidance (see footnote 1 for reference to EIIIP guidance document).
Soda Ash	1990 - 2005	Consumption of soda ash used in consumer products such as glass, soap and detergents, paper, textiles, and food. Emissions based on state's population and estimates of emissions per capita from the US EPA national GHG inventory.	<i>USGS Minerals Yearbook, 2004: Volume I, Metals and Minerals</i> , (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/). For population data, see references for ODS substitutes.
ODS Substitutes	1990 - 2002	Based on state's population and estimates of emissions per capita from the US EPA national GHG inventory.	-- Population data from the Alaska Department of Labor and Workforce Development, "Workforce Information," Home (http://almis.labor.state.ak.us/), Population & Census, Estimates & Projections, Population Data Tables: ---- Data for 1990 through 2000 found under Alaska Population Estimates 2000-2006, Historical Estimates (at bottom of page), Select Borough and Census Area 1990-2000, in Excel file named "02T2-1a.xls." ---- Data for 2001 through 2005 found under Alaska Population Estimates 2000-2006, Vintage 2005 Estimates, Borough and Census Area Estimates, Population by Labor Market Area, Borough and Census Area, and Components of Change, 1990-2005 in Excel file named "05t2-1.xls." -- Data for 2006 through 2029 found under Alaska Population Projections (2005-2029), February 2005 issue of Alaska Economic Trends, in PDF file named "feb05.pdf" (Projections for Alaska population 2005–2029, Table 5. Population Growth Projections Alaska 2005–2029, Medium Population Values in Table 5 used for forecast). -- US 1990-2000 population from US Census Bureau (http://www.census.gov/popest/archives/EST90INTER_CENSAL/US-EST90INT-01.html). -- US 2000-2005 population from US Census Bureau (http://www.census.gov/population/projections/SummaryTabA1.xls).
Electric Power T&D Systems	1990 - 2002	Emissions from 1990 to 2002 based on the national emissions per kilowatt-hour (kWh) and state's electricity use.	National emissions per kWh from US EPA 2005 <i>Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003</i> (http://www.epa.gov/climatechange/emissions/usgginv_archive.html).

Table D2. Approach to Estimating Projections

Source Category	Time Period	Projection Assumptions	Data Source	Annual Growth Rates (%)			
				2000 to 2005	2005 to 2010	2010 to 2015	2015 to 2020
Limestone and Dolomite Consumption	2003 - 2020	Compound annual growth rate for Alaska's employment projections for goods-producing sector (2004-2014). Assumed growth is same for 2015 – 2020 as in previous periods.	Alaska Department of Labor and Workforce Development, "Workforce Information," Industry Forecasts (http://almis.labor.state.ak.us/).	0.95	0.95	0.95	0.95
Soda Ash Consumption	2003 - 2020	Growth between 2004 and 2009 is projected to be about 0.5% per year for US production. Assumed growth is same for 2010 – 2020.	<i>Minerals Yearbook, 2005: Volume 1, Soda Ash</i> , (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/soda_myb05.pdf).	0.5	0.5	0.5	0.5
ODS Substitutes	2003 - 2020	Based on national growth rate for use of ODS substitutes.	EPA, 2004 ODS substitutes cost study report (http://www.epa.gov/ozone/snap/emissions/TMP6si9htnvca.htm).	15.8	7.9	5.8	5.3
Electric Power T&D Systems	2003 - 2020	National growth rate (based on aggregate for all stewardship program categories provided in referenced data source).	U.S. Department of State, <i>U.S. Climate Action Report</i> , May 2002, Washington, D.C., May 2002 (Table 5-7). (http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/SHSU5BNQ76/\$File/ch5.pdf).	3.3	-6.2	-9.0	-2.8

Results

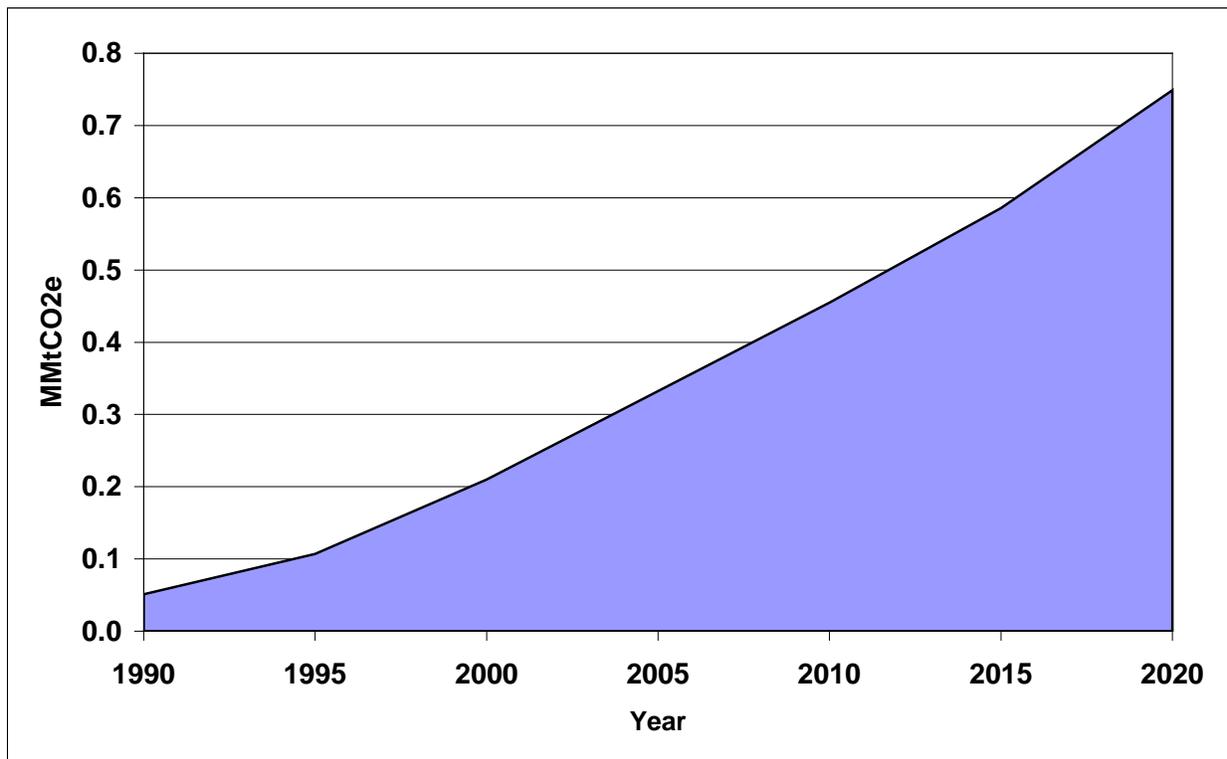
Figures D1 and D2 show historic and projected emissions for the Alaska industrial processes sector from 1990 to 2020. Total gross GHG emissions were about 0.21 million metric tons (MMt) of carbon dioxide equivalent (CO₂e) in 2000, rising to about 0.75 MMTCO₂e in 2020. Emissions from the overall industrial processes category are expected to grow rapidly, as shown in Figures D1 and D2, with emissions growth almost entirely due to the increasing use of HFCs and PFCs in refrigeration and air conditioning equipment.

Substitutes for Ozone-Depleting Substances (ODS)

HFCs and PFCs are used as substitutes for ODS, most notably CFCs (CFCs are also potent warming gases with global warming potentials on the order of thousands of times that of CO₂ per unit of emissions) in compliance with the *Montreal Protocol* and the *Clean Air Act Amendments*

of 1990.⁴⁹ Even low amounts of HFC and PFC emissions, for example, from leaks and other releases associated with normal use of the products, can lead to high GHG emissions on a carbon-equivalent basis. Emissions from the use of ODS substitutes in Alaska were calculated using the default methods in SGIT (see dark green line in Figure D2). Emissions have increased from 0.0007 MMtCO₂e in 1990 to about 0.17 MMtCO₂e in 2000, and are expected to increase at an average rate of 7.6% per year from 2000 to 2020 due to increased substitutions of these gases for ODS. The projected rate of increase for these emissions is based on projections for national emissions from the US EPA report referenced in Table D2.

Figure D1. GHG Emissions from Industrial Processes, 1990-2020



Source: CCS calculations based on approach described in text.

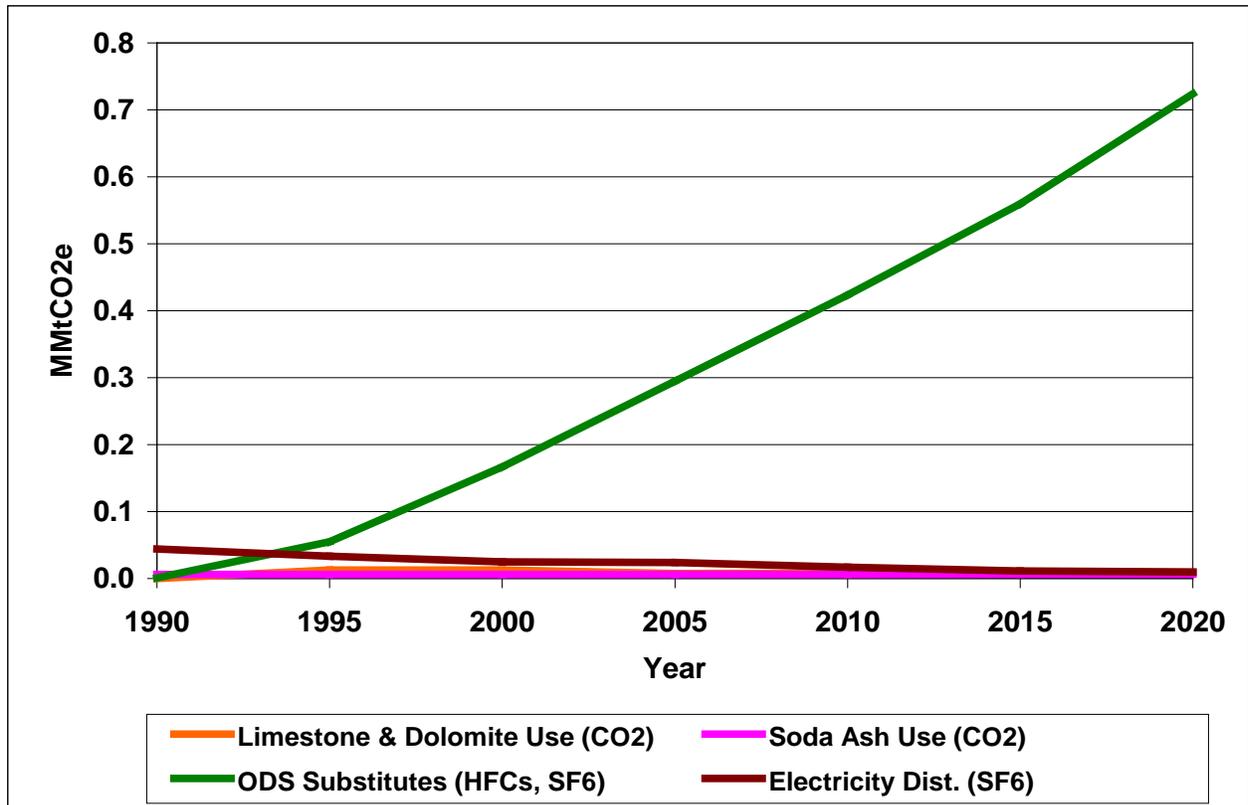
Electricity Distribution

Emissions of SF₆ from electrical equipment have experienced declines since the early nineties (see brown line in Figure D2), mostly due to voluntary action by industry. SF₆ is used as an electrical insulator and interrupter in electricity T&D systems. Emissions for Alaska from 1990 to 2002 were estimated based on the estimates of emissions per kilowatt-hour (kWh) from the

⁴⁹ As noted in EIIP Chapter 6, ODS substitutes are primarily associated with refrigeration and air conditioning, but also many other uses including as fire control agents, cleaning solvents, aerosols, foam blowing agents, and in sterilization applications. The applications, stocks, and emissions of ODS substitutes depend on technology characteristics in a range of equipment. For the US national inventory, a detailed stock vintaging model was used, but this modeling approach has not been completed at the state level.

US EPA GHG inventory and on Alaska’s electricity consumption estimates provided in SGIT. The *US Climate Action Report* shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in Alaska. The decline in SF₆ emissions in the future reflects expectations of future actions by the electric industry to reduce these emissions.

Figure D2. GHG Emissions from Industrial Processes, 1990-2020, by Source



Source: CCS calculations based on approach described in text.

Limestone and Dolomite Consumption

Limestone and dolomite are basic raw materials used by a wide variety of industries, including the construction, agriculture, chemical, glass manufacturing, and environmental pollution control industries, as well as in metallurgical industries such as magnesium production.⁵⁰ Recent historical data for Alaska were not available from the USGS; consequently, the default data provided in SGIT were used to calculate emissions for Alaska (see orange line in Figure D2).

⁵⁰ In accordance with EIIP Chapter 6 methods, emissions associated with the following uses of limestone and dolomite are not included in this category: (1) crushed limestone consumed for road construction or similar uses (because these uses do not result in CO₂ emissions), (2) limestone used for agricultural purposes (which is counted under the methods for the agricultural sector), and (3) limestone used in cement production (which is counted in the methods for cement production).

The employment growth rate for Alaska's goods-producing sector (i.e., 0.95% annual) was used to project emissions to 2020. Relative to total industrial non-combustion process emissions, emissions associated with limestone and dolomite consumption are low (about 0.013 MMtCO₂e in 1995 and 0.009 MMtCO₂e in 2020), and therefore, appear at the bottom of the graph in Figure D2 due to scaling effects. Note that for this sector, SGIT did not contain default consumption data for Alaska for 1990 through 1994 and for 2000. For the purpose of this inventory, consumption for 2000 was assumed to be the same as consumption in 1999.

Soda Ash Consumption

Commercial soda ash (sodium carbonate) is used in many consumer products such as glass, soap and detergents, paper, textiles, and food. CO₂ is also released when soda ash is consumed (see footnote 1 for reference to EIIP guidance document). SGIT estimates historical emissions (see dark pink line in Figure D2) based on the state's population and national per capita emissions from the US EPA national GHG inventory. According to the USGS, this industry is expected to grow at an annual rate of 0.5% from 2004 through 2009 for the U.S. as a whole. Information on growth trends for years later than 2009 was not available; therefore, the same 0.5% annual growth rate was applied for estimating emissions to 2020. Relative to total industrial non-combustion process emissions, emissions associated with soda ash consumption are low (about 0.006 MMtCO₂e in 1990 and 0.0065 MMtCO₂e in 2020), and therefore, cannot be seen in the graph due to scaling effects in Figure D2.

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

- Since emissions from industrial processes are determined by the level of production in and the production processes of a few key industries, and, in some cases, of a few key plants, there is relatively high uncertainty regarding future emissions from the industrial processes category as a whole. Future emissions depend on the competitiveness of Alaskan manufacturers in these industries, and the specific nature of the production processes used in plants in Alaska.
- The projected largest source of future industrial emissions, HFCs and PFCs used in cooling applications, is subject to several uncertainties as well. First, historical emissions are based on national estimates; Alaska-specific estimates are currently unavailable. For example, emissions will be driven by future choices regarding mobile and stationary air conditioning technologies and the use of refrigerants in commercial applications, for which several options currently exist.
- Historical consumption estimates for limestone and dolomite and for soda ash are highly uncertain. Future work should include efforts to improve the historical consumption estimates.
- Greenhouse gases are emitted from several additional industrial processes that are not covered in the EIIP guidance documents, due in part to a lack of sufficient state data on non-energy uses of fossil fuels for these industrial processes. These sources include:

- Iron and Steel Production (CO₂ and CH₄).
- Ammonia Manufacture and Urea Application (CO₂, CH₄, N₂O).
- Aluminum Production (CO₂).
- Titanium Dioxide Production (CO₂).
- Phosphoric Acid Production (CO₂).
- CO₂ Consumption (CO₂).
- Ferroalloy Production (CO₂).
- Petrochemical Production (CH₄).
- Silicon Carbide Production (CH₄).

The CO₂ emissions from the above processes (those listed as CO₂ sources—with the exception of CO₂ consumption and phosphoric acid production) result from the non-energy use of fossil fuels. Although the US EPA estimates emissions for these industries on a national basis, US EPA has not developed methods for estimating the emissions at the state level due to data limitations. If state-level data on non-energy uses of fuels become available, future work should include an assessment of emissions for these source categories.

Appendix E. Fossil Fuel Industries

This appendix reports the GHG emissions that are released during the production, processing, transmission, and distribution of fossil fuels. Known as fugitive emissions, these are methane and carbon dioxide gases released via leakage and venting at coal mines, oil and gas fields, processing facilities, and pipelines. Nationally, fugitive emissions from natural gas systems, petroleum systems, and coal mines accounted for 2.8% of total US greenhouse gas emissions in 2004.⁵¹ Emissions associated with energy consumed by these processes are included in Appendix B (Residential, Commercial and Industrial Sectors).

1.1 Oil and Gas Production

Alaska currently ranks 2nd in crude oil production among US states, totaling 864,000 barrels (bbls) per day and accounting for about 17% of US production.⁵² Proved crude oil reserves sit at 4,327 million barrels, which is 17% of US totals. Oil production in the state peaked in 1988 at 2.017 million bbls per day.⁵³ Alaska has six petroleum refineries, with a combined crude oil distillation capacity of 373,500 barrels per day.⁵⁴

Alaska has two main oil production fields: the Cook Inlet and the North Slope.⁵⁵ While natural gas production is prevalent in Alaska, most of the gas extracted never makes it to U.S. consumers or foreign markets. Of the 3.451 Bcf of natural gas produced on the North Slope in 2005, 92% was re-injected for enhanced oil recovery.⁵⁶

Alaska's potential coal resources are estimated to be 5.5 trillion short tons and may contain up to 1,000 TCF (Trillion cubic feet) of natural gas.⁵⁷ Since drilling the first exploratory coal bed methane (CBM) well in 1994, the state of Alaska has leased over 300,000 acres in the Cook Inlet for coal bed methane development.⁵⁸ While there is continued evaluation of drill sites, including the collection and analysis of coal samples for their methane potential, any CBM development in Alaska faces the challenges of extreme climate and difficult drill rig access. Currently, there is no viable CBM production in Alaska and reserves remain unproven.⁵⁹

⁵¹ "The US Inventory of Greenhouse Gas Emissions and Sinks", US EPA, 2005.

⁵² "Petroleum Profile: Alaska", US DOE Energy Information Administration website, January 2007, Accessed at <http://tonto.eia.doe.gov/oog/info/state/ak.html>.

⁵³ "Petroleum Navigator", US DOE Energy Information Administration website, January 2007, Accessed at <http://tonto.eia.doe.gov/dnav/pet/hist/mcrfpak2a.htm>.

⁵⁴ "Petroleum Profile: Alaska", US DOE Energy Information Administration website, January 2007, Accessed at <http://tonto.eia.doe.gov/oog/info/state/ak.html>.

⁵⁵ Personal communication with Brian Havelock, Alaska DNR Oil and Gas Division, January 22, 2007.

⁵⁶ Alaska Department of Natural Resources: Division of Oil & Gas, Annual Report 2006, Accessed at <http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm>

⁵⁷ Alaska Department of Natural Resources, Division of Oil & Gas, January 2007, Accessed at http://www.dog.dnr.state.ak.us/oil/products/publications/coal_meth/coalbed_methane.htm.

⁵⁸ Coal Bed Methane Drilling in the MatSu Valley, January 2007, Accessed at <http://www.gasdrillingmatsu.org/laws.html>.

⁵⁹ IBID.

1.2 Oil and Gas Industry Emissions

Emissions of methane (CH₄) and entrained carbon dioxide (CO₂) can occur at many stages of production, processing, transmission, and distribution of oil and gas. With over 2,300 active gas and oil wells in the state⁶⁰, 8 operational gas processing plants, 6 oil refineries, and almost 4,000 miles of gas pipelines⁶¹, there are significant uncertainties associated with estimates of Alaska's GHG emissions from this sector. This is compounded by the fact that there are no regulatory requirements to track CO₂ or CH₄ emissions. Therefore, estimates based on actual emissions measurements in Alaska are not possible at this time.

The State Greenhouse Gas Inventory Tool (SGIT) developed by the US EPA facilitates the development of a rough estimate of state-level greenhouse gas emissions.⁶² Methane emission estimates are calculated by multiplying emissions-related activity levels (e.g. miles of pipeline, number of compressor stations) by aggregate industry-average emission factors. Key information sources for the activity data are the US DOE EIA⁶³ and the American Gas Association's annual publication *Gas Facts*.⁶⁴ Methane emissions were estimated using SGIT, with reference to the EPA Emissions Inventory Improvement Program (EIIP) guidance document.

Projections of methane emissions from oil and gas systems are developed based on the following key drivers:

- Natural Gas Consumption – See Appendix A (Electricity Sector), and Appendix B (Residential, Commercial and Industrial Sectors) for assumptions used in projecting natural gas consumption in Alaska. Based on those assumptions, Alaska's natural gas consumption is projected to grow at an average rate of just under 2% annually until 2020.
- Production – Projections for crude oil and natural gas production were pulled from the Alaska Department of Natural Resources Oil and Gas Annual Report 2006. While projected crude oil production varies from year to year, decline rates averaged at 1.3% annually between 2006 and 2015, and increased to 4.8% annually between 2016 and 2020.⁶⁵ Natural gas production is also projected to decline at an average rate of 3.9% annually. Simple assumptions were made for processing and transport growth rates. Any input from reviewers on oil and gas growth or decline rates is appreciated.

Table E1 provides an overview of data sources and approach used to project future emissions.

⁶⁰ Energy Information Administration, Oil & Gas Well Distribution, Accessed at http://www.eia.doe.gov/pub/oil_gas/petrosystem/ak_table.html.

⁶¹ Data from EIA and Gas Facts.

⁶² Methane emissions were calculated using SGIT, with reference to EIIP, Volume VIII: Chapter. 5. "Methods for Estimating Methane Emissions from Natural Gas and Oil Systems", March 2005.

⁶³ "Petroleum Navigator" and "Natural Gas Navigator", US DOE Energy Information Administration website, November 2006, Accessed at <http://www.eia.doe.gov>.

⁶⁴ American Gas Association "Gas Facts, A Statistical Record of the Gas Industry" Referenced annual publications from 1992 to 2004.

⁶⁵ Alaska Department of Natural Resources: Division of Oil & Gas, Annual Report 2006, Tables III.7 and III.8, Accessed at <http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm>. Crude oil proved reserves in Alaska have been declining at an average of almost 3% annually since 1990, as reported by the EIA.

Table E1. Approach to Estimating Historical and Projected Methane Emissions from Natural Gas and Oil Systems.

<i>Activity</i>	Approach to Estimating Historical Emissions		Approach to Estimating Projections
	<i>Required Data for SGIT</i>	<i>Data Source</i>	<i>Projection Assumptions</i>
Natural Gas Drilling and Field Production	Number of wells	EIA	Emissions estimated from Alaska DNR natural gas production forecasts, with an average annual decline of 3.9%. ⁶⁶
	Number of offshore platforms	Alaska DNR Oil and Gas ⁶⁷	
	Miles of gathering pipeline	Gas Facts ⁶⁸	
Natural Gas Processing	Number of gas processing plants	EIA ⁶⁹	Emissions follow trend of natural gas processing, which is estimated to decline 1.4% annually until 2020. ⁷⁰
Natural Gas Transmission	Miles of transmission pipeline	Gas Facts ¹⁹	Emissions follow trend of State gas processing, as above. ⁷¹
	Number of gas transmission compressor stations	EIIP ⁷²	
	Number of gas storage compressor stations	EIIP ⁷³	
	Number of LNG storage compressor stations	Unavailable, assumed negligible.	
Natural Gas Distribution	Miles of distribution pipeline	Gas Facts ¹⁹	Distribution emissions follow State gas consumption trend - annual average growth of 1.8% until 2020. ⁷⁴
	Total number of services	Gas Facts	
	Number of unprotected steel services	Ratio estimated from 2002 data ⁷⁵	

⁶⁶ Assumption based on gas production forecasts from the Alaska DNR Oil and Gas Division Annual Report 2006 for the Cook Inlet and the North Slope, with an average annual decline rate of 3.9% between 2006 and 2020. Projected emissions calculations use the annual growth or decline rate for each year.

⁶⁷ Personal communication, Will Nebesky, Alaska DNR Division of Oil and Gas. January 16, 2007.

⁶⁸ No Gas Facts available for 1991 and 1993, so a linear relationship was assumed to extrapolate from the previous and subsequent year.

⁶⁹ EIA reported data for 2004, and personal communication with Brian Havelock, Alaska DNR, January 22, 2007.

⁷⁰ Decline rate based on EIA gas processing data reported for Alaska, average annual decline of 1.39% in gas processing volume between 2000 and 2004.

⁷¹ It is considered a very low likelihood that an Alaskan natural gas pipeline would be operational prior to 2020, if at all. Personal communication, Brian Havelock, Alaska Department of Natural Resources, Oil and Gas Division, January 22, 2007. Projected emissions from natural gas transmission is assumed to follow gas processing trend as it is processed prior to reinjection in enhanced oil recovery.

⁷² Number of gas transmission compressor stations = miles of transmission pipeline x 0.006 EIIP. Volume VIII: Chapter 5. March 2005.

⁷³ Number of gas storage compressor stations = miles of transmission pipeline x 0.0015 EIIP. Volume VIII: Chapter 5. March 2005.

⁷⁴ Based on US DOE regional projections and electric sector growth assumptions (see Appendix A and B).

⁷⁵ Gas Facts reported unprotected and protected steel services for 2002, but only total services for other years. Therefore the ratio of unprotected and protected steel services in 2002 was assumed to be the ratio for all other years

<i>Activity</i>	Approach to Estimating Historical Emissions		Approach to Estimating Projections
	<i>Required Data for SGIT</i>	<i>Data Source</i>	<i>Projection Assumptions</i>
	Number of protected steel services	Ratio estimated from 2002 data ²⁴	
Oil Production	Annual production	EIA ⁷⁶	Emissions estimated from Alaska DNR oil production forecasts, with an average annual decline rate of 2.7%. ⁷⁷
Oil Refining	Annual amount refined	EIA ⁷⁸	Emissions projected to follow recent trend in State oil refining of 1.5% annual growth. ⁷⁹
Oil Transport	Annual oil transported	Unavailable, assumed oil refined = oil transported	Emissions follow trend of State oil refining, as above.

Note that potential improvements to production, processing, and pipeline technologies resulting in GHG emissions reductions have not been accounted for in this analysis.

A potentially significant source of CO₂, not currently included in this inventory, is that of ‘entrained’ CO₂ in raw gas emerging from the ground. In some areas entrained CO₂ can be significantly above pipeline specifications, and must be separated out at gas processing facilities. Depending on the level of entrained CO₂ in any current natural gas production or future production of Alaskan coal bed methane, emissions of entrained CO₂ may be significant.

1.3 Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. Coal mine methane emissions are usually considerably higher, per unit of coal produced, from underground mining than from surface mining.

Alaska has one operational surface coal mine, which produced almost 1.5 million short tons of coal in 2005.⁸⁰ As reported in this inventory, methane emissions from coal mines are as reported by the EPA, and include emissions from surface coal mines and post-mining activities.⁸¹

(0.4891 for protected services and 0.0045 for unprotected services). This yields more congruent results than the EIIP guidance of using multipliers of 0.2841 for protected steel services, and 0.0879 for unprotected steel services.

⁷⁶ Data extracted from the EIA Petroleum Supply Annual for each year.

⁷⁷ Assumption based on crude oil production forecasts from the Alaska DNR Oil and Gas Division Annual Report 2006 for the Cook Inlet and the North Slope. Average annual decline rate of 2.7% between 2006 and 2020. Projected emissions calculations use the annual growth or decline rate for each year.

⁷⁸ Refining assumed to be equal to the total input of crude oil into the Petroleum Administration for Defense District (PADD) V (West Coast) times the ratio of Alaska’s refining capacity to PADD V’s total refining capacity. No data for 1995 and 1997, so linear relationship assumed from previous and subsequent years.

⁷⁹ Based on EIA data, average growth in crude refined annually was 1.5% between 2000 and 2004.

⁸⁰ EIA Coal Data Accessed at <http://www.eia.doe.gov/cneaf/coal/page/acr/table1.html>.

⁸¹ Emissions from EPA *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004* (April 2006) Accessed at <http://epa.gov/climatechange/emissions/usinventoryreport.html>

Methane emissions from coal mining have remained fairly steady with an average annual increase in methane emissions of 0.4% between 1990 and 2004. As an initial and simple estimate, coal mine methane emissions are projected to continue to increase at 0.4% annually until 2020. We welcome any input from reviewers in this regard.

1.4 Results

Table E2 displays the estimated methane emissions from the fossil fuel industry in Alaska from 1990 to 2005, with projections to 2020. Emissions from this sector declined by an estimated 40% from 1990 to 2005, and are projected to decrease by a further 28% between 2005 and 2020. Crude oil production is the single greatest contributor to GHG emissions from the Alaskan fossil fuel industry.

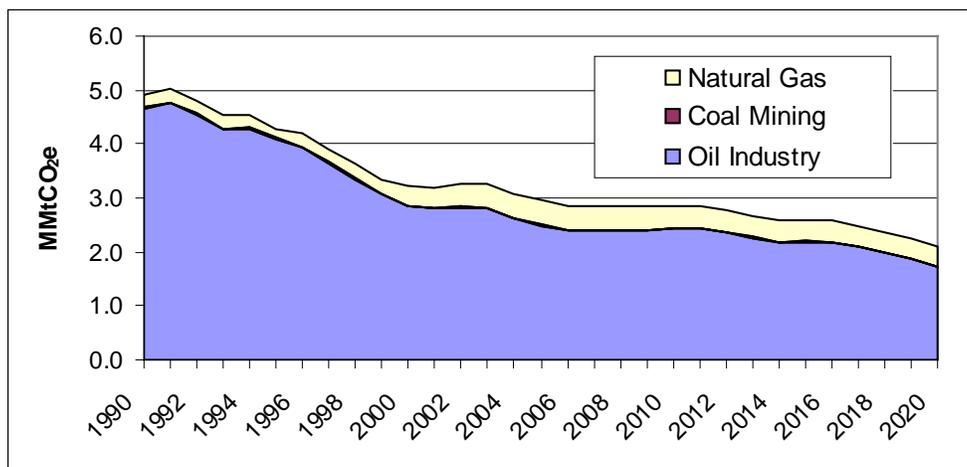
Table E2. Methane Emissions and Projections from the Fossil Fuel Industry

Fossil Fuel Industry	4.92	4.29	3.22	2.95	2.86	2.62	2.13
Natural Gas Industry	0.25	0.17	0.38	0.45	0.43	0.42	0.41
Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Processing	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Transmission	0.1	0.0	0.1	0.1	0.1	0.1	0.1
Distribution	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Oil Industry	4.7	4.1	2.8	2.5	2.4	2.2	1.7
Production	4.7	4.1	2.8	2.5	2.4	2.2	1.7
Refineries	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Mining (Methane)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

0.0 in the above chart means the value is less than 50,000 metric tons CO₂e. Estimates do not include any entrained CO₂ from natural gas production.

Figure E1 displays the methane emissions from coal mining and natural gas and oil systems, on a million tonnes CO₂ equivalency basis.

Figure E1. Fossil Fuel Industry Emission Trends (MMtCO₂e)



Emissions from the coal mining sector are too small to be seen in this chart.

Key Uncertainties

Key sources of uncertainty underlying the estimates above are as follows:

- Current levels of fugitive emissions. These are based on industry-wide averages, and until estimates are available for specific facilities significant uncertainties remain.
- The degree to which the State Greenhouse Gas Inventory Tool (SGIT) emission factors are applicable to the fossil fuel industry in Alaska.
- Projections of future production of fossil fuels. These industries are difficult to forecast, as they are affected by a mix of drivers, including: economics, resource supply, fuels demand, technology development, and the status of regulations applying to the industry, among others. The ADNR Oil & Gas projections are considered to be fairly conservative estimates,⁸² and may not include any significant changes in energy prices, relative to today's prices. Large price swings, resource limitations, or changes in regulations could significantly change future production and the associated GHG emissions.
- Future natural gas transmission lines to transport Alaskan North Slope natural gas to Canada or the lower 48 states.⁸³
- Other significant uncertainties include the fraction of entrained CO₂ in any current natural gas production or future CBM production and potential emissions reducing improvements in oil and gas production, processing, and pipeline technologies.

⁸² Personal communication, Brian Havelock, Alaska Department of Natural Resources, Oil and Gas Division, January 22, 2007.

⁸³ It is considered a very low likelihood that an Alaskan natural gas pipeline would be operational prior to 2020, if at all. Personal communication, Brian Havelock, Alaska Department of Natural Resources, Oil and Gas Division, January 22, 2007.

Appendix F. Agriculture

Overview

The emissions discussed in this appendix refer to non-energy methane (CH₄) and nitrous oxide (N₂O) emissions from enteric fermentation, manure management, and agricultural soils. Emissions and sinks of carbon in agricultural soils are also covered. Energy emissions (combustion of fossil fuels in agricultural equipment) are included in the residential, commercial, and industrial (RCI) fuel consumption sector estimates.

There are two livestock sources of greenhouse gas (GHG) emissions: enteric fermentation and manure management. Methane emissions from enteric fermentation are the result of normal digestive processes in ruminant and non-ruminant livestock. Microbes in the animal digestive system breakdown food and emit CH₄ as a by-product. More CH₄ is produced in ruminant livestock because of digestive activity in the large fore-stomach. Methane and N₂O emissions from the storage and treatment of livestock manure (e.g., in compost piles or anaerobic treatment lagoons) occur as a result of manure decomposition. The environmental conditions of decomposition drive the relative magnitude of emissions. In general, the more anaerobic the conditions are, the more CH₄ is produced because decomposition is aided by CH₄ producing bacteria that thrive in oxygen-limited aerobic conditions. Under aerobic conditions, N₂O emissions are dominant. Emissions estimates from manure management are based on manure that is stored and treated on livestock operations. Emissions from manure that is applied to agricultural soils as an amendment or deposited directly to pasture and grazing land by grazing animals are accounted for in the agricultural soils emissions.

The management of agricultural soils can result in N₂O emissions and net fluxes of carbon dioxide (CO₂) causing emissions or sinks. In general, soil amendments that add nitrogen to soils can also result in N₂O emissions. Nitrogen additions drive underlying soil nitrification and denitrification cycles, which produce N₂O as a by-product. The emissions estimation methodologies used in this inventory account for several sources of N₂O emissions from agricultural soils, including decomposition of crop residues, synthetic and organic fertilizer application, manure application, sewage sludge, nitrogen fixation, and histosols (high organic soils, such as wetlands or peatlands) cultivation. Both direct and indirect emissions of N₂O occur from the application of manure, fertilizer, and sewage sludge to agricultural soils. Direct emissions occur at the site of application and indirect emissions occur when nitrogen leaches to groundwater or in surface runoff and is transported off-site before entering the nitrification/denitrification cycle. Methane and N₂O emissions also result when crop residues are burned. Methane emissions occur during rice cultivation; however, rice is not grown in Alaska.

The net flux of CO₂ in agricultural soils depends on the balance of carbon losses from management practices and gains from organic matter inputs to the soil. Carbon dioxide is absorbed by plants through photosynthesis and ultimately becomes the carbon source for organic matter inputs to agricultural soils. When inputs are greater than losses, the soil accumulates carbon and there is a net sink of CO₂ into agricultural soils. In addition, soil disturbance from the cultivation of histosols releases large stores of carbon from the soil to the atmosphere. Finally, the practice of adding limestone and dolomite to agricultural soils results in CO₂ emissions.

Emissions and Reference Case Projections

Methane and Nitrous Oxide

GHG emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.⁸⁴ In general, the SGIT methodology applies emission factors developed for the US to activity data for the agriculture sector. Activity data include livestock population statistics, amounts of fertilizer applied to crops, and trends in manure management practices. This methodology is based on international guidelines developed by sector experts for preparing GHG emissions inventories.⁸⁵

Data on crop production in Alaska from 1990 to 2005 and the number of animals in the state from 1990 to 2002 were obtained from the United States Department of Agriculture (USDA), National Agriculture Statistical Service (NASS) and incorporated as defaults in SGIT.⁸⁶ Future reference case emissions from enteric fermentation and manure management were estimated based on the annual growth rate in emissions (million metric ton [MMt] carbon dioxide equivalent [CO₂e] basis) associated with historical livestock populations in Alaska for 1990 to 2002. The default data in SGIT accounting for the percentage of each livestock category using each type of manure management system was used for this inventory. Default SGIT assumptions were available for 1990 through 2002.

Data on fertilizer usage came from *Commercial Fertilizers*, a report from the Fertilizer Institute. Data on crop production in Alaska from 1990 to 2005 from the USDA NASS were used to calculate N₂O emissions from crop residues and CH₄ emissions from agricultural residue burning through 2005. Emissions for the other agricultural crop production categories (i.e., synthetic and organic fertilizers) were calculated through 2002. Production data from NASS was available for only two (i.e., barley and oats) of the types of crops included in SGIT, and these crops do not use nitrogen; therefore, N₂O emissions were not estimated for crops that use nitrogen (i.e., nitrogen fixation). Also, data were not available to estimate nitrogen released by the cultivation of histosols (i.e., the number of acres of high organic content soils). In addition, net carbon fluxes from agricultural soils are not reported in the US Inventory of Greenhouse Gas Emissions and Sinks⁸⁷ and the US Agriculture and Forestry Greenhouse Gas Inventory.

⁸⁴ GHG emissions were calculated using SGIT, with reference to EIIP, Volume VIII: Chapter 8. "Methods for Estimating Greenhouse Gas Emissions from Livestock Manure Management", August 2004; Chapter 10. "Methods for Estimating Greenhouse Gas Emissions from Agricultural Soil Management", August 2004; and Chapter 11. "Methods for Estimating Greenhouse Gas Emissions from Field Burning of Agricultural Residues", August 2004.

⁸⁵ Revised 1996 Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories, published by the National Greenhouse Gas Inventory Program of the IPCC, available at <http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm>; and Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, published in 2000 by the National Greenhouse Gas Inventory Program of the IPCC, available at: <http://www.ipcc-nggip.iges.or.jp/public/gp/english/>.

⁸⁶ USDA, NASS (http://www.nass.usda.gov/Statistics_by_State/Alaska/index.asp).

⁸⁷ US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004 (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006. Available at: <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

There is some agricultural residue burning conducted in Alaska. The SGIT methodology calculates emissions by multiplying the amount (e.g., bushels or tons) of each crop produced by a series of factors to calculate the amount of crop residue produced and burned, the resultant dry matter, and the carbon/nitrogen content of the dry matter. For Alaska, the default SGIT method was used to calculate emissions because activity data in the form used in the SGIT were not readily available. Future work on this category should include an assessment to refine the SGIT default assumptions.

Table F1 shows the annual growth rates applied to estimate the reference case projections by agricultural sector. Emissions from enteric fermentation and agricultural soils were projected based on the annual growth rate in historical emissions (MMtCO₂e basis) for these categories in Alaska for 1990 to 2002 (1990 to 2005 for crop residues and nitrogen fixing crops). For crop residues, data for 1990 through 1993 were not available; therefore, the annual growth rate is based on the last 11 years for which historical emissions were calculated. Note that during 2000, weather conditions caused a significant decline in barley and oat production (both the number of acres harvested and yields); however, production of these crops recovered to typical levels in 2001 through 2005.⁸⁸

Table F1. Growth Rates Applied for the Agricultural Sector

Agricultural Category	Growth Rate	Basis for Annual Growth Rate*
Enteric Fermentation	2.7%	Historical emissions for 1990-2002.
Manure Management	6.1%	Historical emissions for 1997-2002.
Agricultural Burning	0.0%	Assumed no growth.
Agricultural Soils – Direct Emissions		
Fertilizers	-4.3%	Historical emissions for 1990-2002.
Crop Residues	2.0%	Historical emissions for 1994-2005.
Nitrogen-Fixing Crops	0.0%	No historical data available.
Histosols	0.0%	No historical data available.
Livestock	2.1%	Historical emissions for 1990-2002.
Agricultural Soils – Indirect Emissions		
Fertilizers	-4.3%	Historical emissions for 1990-2002.
Livestock	2.4%	Historical emissions for 1990-2002.
Leaching/Runoff	-2.8%	Historical emissions for 1990-2002.

* Except for manure management and crop residues, compound annual growth rates shown in this table were calculated using the growth rate in historical emissions (MMtCO₂e basis) from 1990 through the most recent year of data. These growth rates were applied to forecast emissions from the latest year of data to 2020. For crop residues, data for 1990 through 1993 were not available; therefore, the annual growth rate is based on the last 11 years for which historical emissions were calculated. For manure management, the growth rate is based on emissions calculated for 1997-2002 (see text for explanation).

For manure management, the 12-year historical growth rate is 15.4% and the 5-year growth rate (based on 1997 through 2002 emissions) is 6.1%. The high 12-year growth rate is driven by changes in the SGIT assumptions on the types of manure management systems applied for dairy cattle and heifers. For dairy cattle and heifers, the proportion of manure managed in systems that yield higher GHG emissions (e.g., anaerobic lagoons and liquid slurry) than other systems (e.g.,

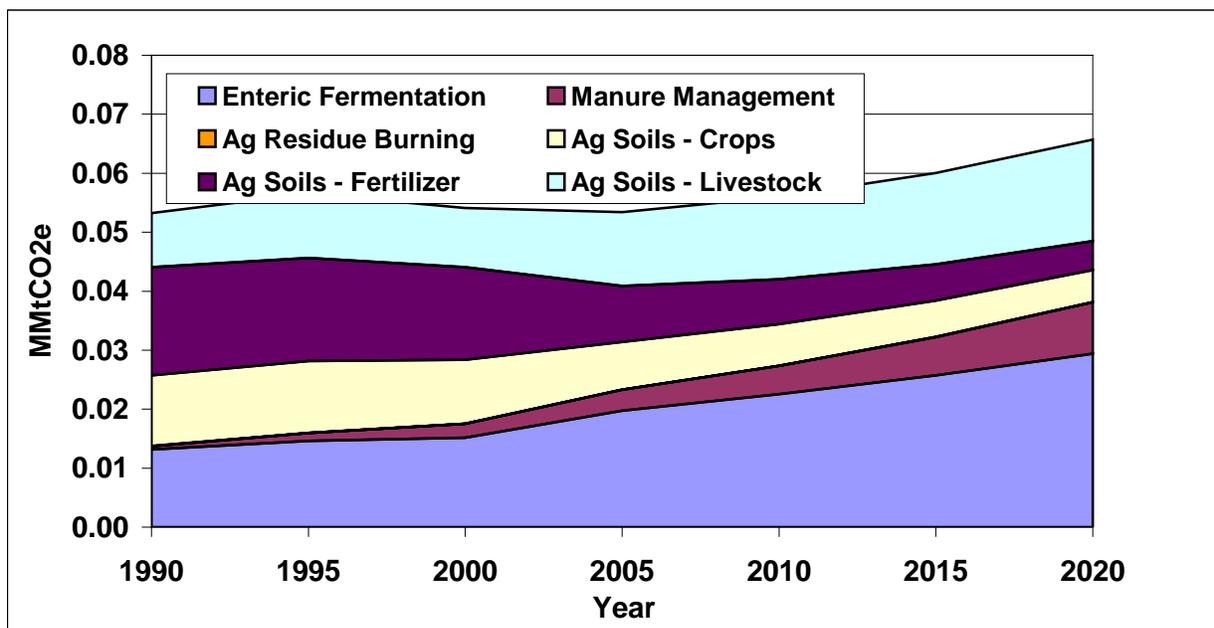
⁸⁸ Alaska Agricultural Statistics 2001, prepared by Alaska Agricultural Statistics Service, USDA, Palmer, Alaska.
Alaska Department of Environmental Conservation

pasture) increased from 0% in 1990 to over about 70% for 1997 through 2002. For this analysis, the 5-year growth rate was assumed to be more representative of future manure management practices in Alaska and was used to forecast emissions from 2002 to 2020.

Results

As shown in Figure F1, gross GHG emissions from agricultural sources range between about 0.053 and 0.066 MMtCO₂e from 1990 through 2020, respectively. In 1990, enteric fermentation accounted for about 25% (0.013 MMtCO₂e) of total agricultural emissions and is estimated to account for about 45% (0.029 MMtCO₂e) of total agricultural emissions in 2020. The manure management category, which shows the highest rate of growth relative to the other categories, accounted for 1% (0.001 MMtCO₂e) of total agricultural emissions in 1990 and is estimated to account for about 13% (0.009 MMtCO₂e) of total agricultural emissions in 2020. The agricultural soils category shows declining growth, with 1990 emissions accounting for 74% (0.039 MMtCO₂e) of total agricultural emissions and 2020 emissions estimated to be about 42% (0.028 MMtCO₂e) of total agricultural emissions.

Figure F1. Gross GHG Emissions from Agriculture



Source: CCS calculations based on approach described in text.

Notes: Ag Soils – Crops category includes crop residues (no cultivation of histosols estimated); emissions for agricultural residue burning are too small to be seen in this chart.

Agricultural burning emissions were estimated to be very small based on the SGIT activity data (<0.00001 MMtCO₂e/yr from 1990 to 2002). This agrees with the USDA Inventory which also reports a low level of residue burning emissions (0.02 MMtCO₂e).

The standard IPCC source categories missing from this report is CO₂ emissions from limestone and dolomite application and CO₂ fluxes in agricultural soils. Estimates for Alaska were not

available; however, the USDA's national estimate for soil liming is about 9 MMtCO₂e/yr.⁷ As mentioned above the USDA national estimates for soil carbon do not include Alaska.

Key Uncertainties

Emissions from enteric fermentation and manure management are dependent on the estimates of animal populations and the various factors used to estimate emissions for each animal type and manure management system (i.e., emission factors which are derived from several variables including manure production levels, volatile solids content, and CH₄ formation potential). Each of these factors has some level of uncertainty. Also, animal populations fluctuate throughout the year, and thus using point estimates introduces uncertainty into the average annual estimates of these populations. In addition, there is uncertainty associated with the original population survey methods employed by USDA. The largest contributors to uncertainty in emissions from manure management are the emission factors, which are derived from limited data sets.

As mentioned above, for Alaska data were not available for estimating emissions associated with changes in agricultural soil carbon levels and limestone and dolomite application. When newer data are released by the USDA, these should be reviewed to represent current conditions as well as to assess trends.

Alaska has reindeer husbandry operations which are not included in SGIT. The number of head of reindeer in Alaska has declined in recent years (from 24,000 head in 1998 to 15,000 in 2005).⁸⁹ Future work should consider developing data for estimating emissions associated with reindeer husbandry operations if this category is determined to be important.

Another contributor to the uncertainty in the emission estimates is the projection assumptions. This inventory assumes that the average annual rate of change in future year emissions will follow the historical average annual rate of change from 1990 through the most recent year of data. For example, the historical data show a decline in the use of fertilizers; however, there may be a leveling-off in fertilizer use trends due to recent efficiency gains that may be close to reaching their full technical potential.

⁸⁹ Alaska Agricultural Statistics 2006, prepared by Alaska Field Office, USDA NASS, Palmer, Alaska.

Appendix G. Waste Management

Overview

GHG emissions from waste management include:

- Solid waste management – CH₄ emissions from municipal and industrial solid waste landfills (LFs), accounting for CH₄ that is flared or captured for energy production (this includes both open and closed landfills);
- Solid waste combustion – CH₄, CO₂, and N₂O emissions from the combustion of solid waste in incinerators or waste to energy plants; and
- Wastewater management – CH₄ and N₂O from municipal wastewater and CH₄ from industrial wastewater (WW) treatment facilities.

Inventory and Reference Case Projections

Solid Waste Management

For solid waste management, we used the U.S. EPA SGIT and the U.S. EPA Landfill Methane Outreach Program (LMOP) landfills database⁹⁰ as starting points to estimate emissions. The LMOP data serve as input data to estimate annual waste emplacement for each landfill needed by SGIT. SGIT then estimates CH₄ generation for each landfill site. Additional post-processing outside of SGIT to account for controls is then performed to estimate CH₄ emissions.

Since the LMOP database contained information on only the Anchorage LF, CCS contacted DEC staff to gather additional information on solid waste landfills and other solid waste management issues, including waste combustion.⁹¹ From these contacts, CCS learned that there are approximately 300 small landfills in Alaska. About 250 of these are considered Class III sites that accept less than 5 tons per day (tpd). The other 50 are Class II sites that accept between 5 and 20 tpd. For the Class III sites, half of the waste accepted is assumed to be open burned. Most of these community sites have been in operation since the 1960s, if not earlier.

The only landfill site currently controlled in AK is the Anchorage site, which collects and flares the methane generated. A partial collection system has been installed at the Juneau LF, however the amount of methane has not been sufficient for flaring. Hence, this site and all of the other landfills in AK are considered in this analysis to be uncontrolled. The Class III sites and the Class II sites were combined for the purposes of emissions modeling. To estimate waste in place at these sites, CCS assumed that each Class II site accepted 12.5 tpd and that each site operated 5 days per week. Class III sites were assumed to accept 2.5 tpd at each site for 5 days per week. Half of the waste at Class III sites is assumed to be open burned on-site. All sites were assumed to be open since the 1960s (waste emplaced much more than about 30 years ago is not expected

⁹⁰ LMOP database is available at: <http://www.epa.gov/lmop/proj/index.htm>. Updated version of the database provided by Rachel Goldstein, Program Manager, EPA Landfill Methane Outreach Program, October 2006. The only AK site represented in the database was the Anchorage Regional LF.

⁹¹ Doug Buteyn and Ed Emswiler, ADEC, Solid Waste Division, personal communications with S. Roe, CCS, December 2006 – January 2007.

to be producing significant amounts of methane). The table below provides a summary of the data used as input to SGIT for modeling emissions.

Table G1. Summary of Municipal Solid Waste Landfill Data

Site Name	Operating Years	Average Waste Emplacement Rate (tons/yr)	Control
Anchorage Regional LF	1987 - Present	350,000	Flare
Juneau LF ^a	2004 - Present	23,400	None
Class II LFs (50 sites)	1960's - Present	162,500	None
Class III LFs (250 sites)	1960's - Present	81,250	None
^a Prior to 2004, combustible waste was incinerated and is accounted for under the waste combustion sector. A collection and flare system is in place; however, currently the methane is mostly being vented.			

The estimated average annual disposal rates for each landfill were used in SGIT for all years that the landfills were operating (Class II and III landfills were each modeled as a single site). CCS performed two different runs of SGIT to estimate emissions from municipal solid waste (MSW) landfills: (1) uncontrolled landfills; (2) landfills with a landfill gas collection system and flare (the Anchorage site). The other landfill category that CCS commonly models is sites with landfill gas to energy (LFGTE) plants. There are none of these currently operating in Alaska.

After obtaining the methane generation data from SGIT, CCS performed some post-processing of the methane emissions to account for landfill gas controls (flared sites) and to project the emissions through 2020. For the controlled landfills, CCS assumed that the overall methane collection and control efficiency is 75%.⁹² Of the methane not captured by a landfill gas collection system, it is further assumed that 10% is oxidized before being emitted to the atmosphere (consistent with the SGIT default). This assumption for oxidation is also used for the methane emitted from uncontrolled sites.

Growth rates were estimated by using the historic (1995-2005) growth rates of emissions in both the controlled and uncontrolled landfill categories. The annual growth rates are: 2.9% for uncontrolled sites and 9.0% for flared site (Anchorage). The higher growth rate for Anchorage is driven by the fact that this is a relatively young site (<20 years), which is receiving a fairly large amount of waste annually (350,000 tons).

For industrial waste landfills, SGIT calculates emissions based on an assumption that industrial waste is emplaced at a selected fraction of municipal solid waste emplaced (the default is based on national data and is 7% of municipal solid waste emplaced). Due to the lack of a substantial industrial base in Alaska, CCS assumed that any industrial waste emplaced in solid waste landfills is captured in the municipal solid waste emplacement estimates described above. Hence, there are no emissions estimated for the industrial waste landfills sector.

⁹² As per EPA's AP-42 Section on Municipal Solid Waste Landfills:
<http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf>.

Solid Waste Combustion

Information from ADEC contacts was used to construct estimates from municipal solid waste combustion that occurred during the 2000 – 2005 time-frame.⁹³ Solid waste combustion addressed here includes both the controlled combustion of municipal solid waste in incinerators, as well as open municipal solid waste combustion occurring at community landfills. For controlled combustion, prior to 2000, the SGIT default activity data were used.⁹⁴ From 2000-2005, information provided by ADEC staff were used (the 2002 estimates were used to represent 2000 to 2003 activity; 2004 and 2005 activity were estimated by subtracting the throughput for the Juneau facility, which closed in 2004).

The mass of controlled waste combustion was added to the estimate described under the landfills section above for open burning at Class III landfill sites (81,250 tons/yr) to estimate total waste combustion emissions. This value for open burning was used for all years due to availability of data. The table below shows the total waste mass estimates per year.

Table G2. Summary of Municipal Solid Waste Combustion Data (tons)

Combustion Category	1990	1995	2000	2005
Controlled Burning	45,990	75,000	111,360	90,401
Open Burning	81,250	81,250	81,250	81,250
Totals	127,240	156,250	192,610	171,651

SGIT does not use different methods (emission factors) for open and controlled burning. Therefore, the total waste estimates above were used as input to SGIT to estimate emissions. ADEC also provided some data for sewage sludge incineration. Most of the carbon in sewage sludge is of biological origin, and therefore the associated CO₂ emissions would not be incorporated into this GHG inventory. While we would expect some emissions of methane and nitrous oxide from these sources, CCS believes that the emissions would be negligible.

Emissions for the solid waste combustion sector were forecast based on Alaska’s forecasted population growth from 2005-2020 (0.69%/yr).⁹⁵

Wastewater Management

GHG emissions from municipal and industrial wastewater treatment were also estimated. For municipal wastewater treatment, emissions are calculated in EPA’s SGIT based on state population, assumed biochemical oxygen demand (BOD) and protein consumption per capita, and emission factors for N₂O and CH₄. The key SGIT default values are shown in Table G3

⁹³ Controlled burning - Alice Edwards, ADEC, personal communication and data file provided to S. Roe, CCS, January 2007. Open burning – Doug Buteyn, ADEC, personal communication with S. Roe, CCS, December 2006.

⁹⁴ SGIT reference for solid waste combustion data appears to be *Biocycle*, “Annual Survey of Municipal Waste Management Practices: State of Garbage in America”, date not provided.

⁹⁵ Alaska Department of Labor and Workforce Development, “Workforce Information,” Home, Population & Census, Estimates & Projections, Population Data Tables, “Alaska Population Projections (2005-2029),” Select “February 2005 issue of Alaska Economic Trends,” in PDF file named “feb05.pdf”(Projections for Alaska population 2005–2029, Table 5. Population Growth Projections Alaska 2005–2029, Medium Population Values in Table 5 used for forecast).

below. Emissions for the municipal wastewater management sector were forecast based on Alaska’s forecasted population growth from 2005-2020 (0.69%/yr).

For industrial wastewater emissions, SGIT provides default assumptions and emission factors for three industrial sectors: Fruits & Vegetables, Red Meat & Poultry, and Pulp & Paper. According to ADEC contacts and the Dun & Bradstreet database, there aren’t currently any large operations in these industry sectors that would be expected to have their own treatment systems. According to the contact at the Alyeska Valdez Marine terminal, the Valdez ballast water treatment facility does not emit CH₄ emissions.⁹⁶

Emissions of methane are also expected to occur from fish processing waste dumped at sea.⁹⁷ Again, CCS attempted to gather information on this issue; however no emissions-related information was identified. Presumably, methane emissions would also occur from waste treatment conducted on-shore; however, CCS is not aware of any data or emissions estimation methods to address this potential source category.

Table G3. SGIT Key Default Values for Municipal Wastewater Treatment

Variable	Value
BOD	0.065 kg /day-person
Amount of BOD anaerobically treated	16.25%
CH ₄ emission factor	0.6 kg/kg BOD
Alaska residents not on septic	75%
Water treatment N ₂ O emission factor	4.0 g N ₂ O/person-yr
Biosolids emission Factor	0.01 kg N ₂ O-N/kg sewage-N
Source: U.S. EPA State Inventory Tool – Wastewater Module; methodology and factors taken from U.S. EPA, Emission Inventory Improvement Program, Volume 8, Chapter 12, October 1999: www.epa.gov/ttn/chief/eiip/techreport/volume08/ .	

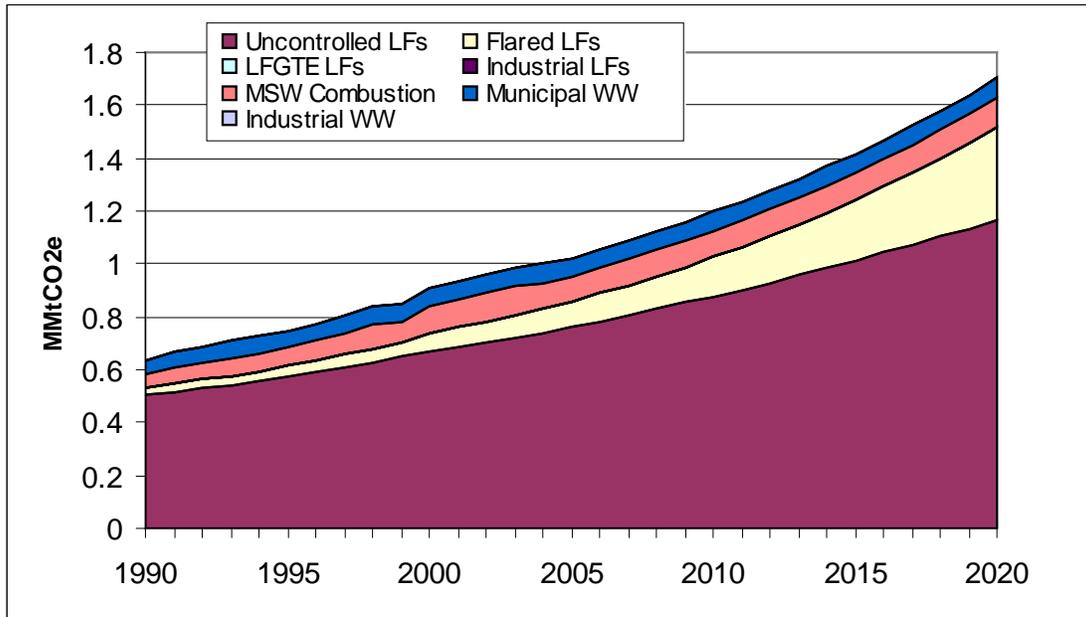
Figure G1 shows the emission estimates for the waste management sector. Overall, the sector accounts for 1.0 MMtCO₂e in 2005. By 2020, emissions are expected to grow to 1.7 MMtCO₂e/yr. The growth in emissions is driven by the solid waste management sector, in particular uncontrolled and flared landfills. In 2005, 75% of the emissions were contributed by the uncontrolled landfills sector. By 2020, the contribution from these sites is expected to be about 70%. For flared LFs (the Anchorage Regional LF), the contribution to the sector total was about 9% in 2005 growing to over 20% by 2020.

As described above, no emissions are estimated historically or in the future for the LFGTE or industrial LF categories. Any industrial solid waste that is generated is assumed to be captured within the municipal solid waste estimates. No LFGTE sites currently operate in Alaska.

⁹⁶ Brad Thomas, Alyeska Valdez Marine Terminal, personal communication with Steve Roe, CCS, January, 2007.

⁹⁷ An estimate from the early 1990’s is that about 1.7 million metric tons of fish waste is generated in Alaska. The amount generated and treated on-shore versus at sea was not provided (*Pollution Prevention Opportunities in the Fish Processing Industry*, Pacific Northwest Pollution Prevention Research Center, 1993).

Figure G1. Alaska GHG Emissions from Waste Management



Notes: LF – landfill; WW – wastewater; LFGTE – landfill gas to energy; historic and future emissions for the LFGTE landfill and industrial solid waste landfill categories were estimated to be zero in AK. Sources of information to estimate emissions for the industrial WW treatment category could not be obtained for incorporation into this assessment.

The wastewater treatment sector is estimated to contribute 7% of the sector emissions in 2005 and less than 5% of the total by 2020. Note that these estimates currently only include the municipal wastewater treatment sector. Data and methods were not identified to incorporate industrial wastewater treatment emissions into this assessment (including fish processing waste).

Key Uncertainties

The methods used to model landfill gas emissions do not adequately account for the points in time when controls were applied at individual sites. Hence, for landfills, the historical emissions are less certain than current emissions and future emissions for this reason (since each site that is currently controlled was modeled as always being controlled, the historic emissions are low as a result; for Alaska, this is only an issue with the Anchorage LF). The modeling also does not account for uncontrolled sites that will need to apply controls during the period of analysis due to triggering requirements of the federal New Source Performance Standards/Emission Guidelines. As noted above, the available data do not cover all of the open and closed landfills in Alaska. Rough estimates were developed for approximately 50 Class II and 250 Class III landfills in the state. Hence, the estimates presented here should be viewed as order of magnitude estimates.

The waste combustion estimates should also be viewed as order of magnitude estimates given the availability of data. The estimates are based on assumptions that 50% of the waste at 250 Class III sites is open burned. National default waste composition profiles are used to estimate the CO₂e emissions for this activity, which might not adequately reflect the types of waste being

open burned. No significant changes in controlled waste burning (in municipal waste combustors) are assumed for the future. Growth overall in waste combustion emissions is assumed to track population growth.

For the wastewater sector, the key uncertainties are associated with the application of SGIT default values for the municipal wastewater treatment parameters listed in Table G1 above (e.g. fraction of the Alaska population on septic; fraction of BOD which is anaerobically decomposed). The SGIT defaults were derived from national data.

For industrial wastewater treatment, data and estimation methods were lacking for this assessment. Emissions are expected from the treatment of fish processing waste; however no information was identified to develop emission estimates.

Appendix H. Forestry

Overview

Forestland emissions refer to the net carbon dioxide (CO₂) flux⁹⁸ from forested lands in Alaska, which account for about 35% of the state's land area.⁹⁹ About 10% of Alaska's forests are temperate coastal forests with the remainder being the interior boreal forests. Sitka spruce, hemlock and cedar are the dominant species in the southeast and south-central coastal parts of the state, while white spruce, black spruce, black cottonwood, aspen, and paper birch are found in the interior forests.

Forestlands are net sinks of CO₂ in Alaska. Through photosynthesis, CO₂ is taken up by trees and plants and converted to carbon in biomass within the forests. CO₂ emissions occur from respiration in live trees and decay of dead biomass. In addition, carbon is stored for long time periods when forest biomass is harvested for use in durable wood products. CO₂ flux is the net balance of CO₂ removals from and emissions to the atmosphere from the processes described above.

CCS has also included information on methane emissions from Alaskan ecosystems. These emissions are considered natural sources of methane that may be indirectly influenced by climate change. The estimated emissions documented below are not included within the summary tables presented in the body of this report, since they are considered natural sources.

Inventory and Reference Case Projections

CO₂ Flux in Alaska's Forests

For over a decade, the United State Forest Service (USFS) has been developing and refining a forest carbon modeling system for the purposes of estimating forest carbon inventories. The methodology is used to develop national forest CO₂ fluxes for the official US Inventory of Greenhouse Gas Emissions and Sinks.¹⁰⁰ The national estimates are compiled from state-level data. Unfortunately, the USFS has not yet developed estimates for Alaska due to a lack of comprehensive survey data for the State needed to develop these estimates.

Alaska is unique because a large fraction of the land base is essentially untouched, pristine forestland. GHG inventories principally account for *anthropogenic* emissions and sinks. In the forestry sector, experts have determined that a practical approach to quantifying anthropogenic emissions and sinks is to inventory carbon fluxes and non-CO₂ emissions on "managed" forestland only. The USFS forest carbon accounting system incorporates these principles to a large degree because the Forest Inventory and Analysis survey (FIA) upon which they are based

⁹⁸ "Flux" refers to both emissions of CO₂ to the atmosphere and removal (sinks) of CO₂ from the atmosphere.

⁹⁹ Alaska Forest Association, <http://www.akforest.org/facts.htm>, reports 129 million acres of forested lands. The total land area in AK is 365 million acres (http://www.netstate.com/states/geography/ak_geography.htm). Data used in this appendix from UAF are based on geographic information indicating that AK has about 162 million acres of forested lands (about 23 million acres are in the temperate (coastal) maritime forest).

¹⁰⁰ *US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004* (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006. Available at: <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

targets managed forestlands (although all forested lands are included in the carbon flux estimates).

CCS used research studies provided by experts from the University of Alaska to construct estimates of the forest carbon flux in Alaska that are comparable in principle to the standard USFS inventory approach. The methods and results presented here cover both the entire forestland base in AK, as well as the temperate (coastal) maritime forests. The coastal maritime forests are where much of Alaska's productive forests are and where most the management has occurred historically. For the purposes of this analysis, CCS considers these to represent the State's "managed" forests.

Yarie and Billings provided estimates for Alaska's boreal forests that indicated annual sequestration rates of about -35 MMtCO₂.¹⁰¹ Boreal forests represent about one-third of the forests in Alaska. UAF researchers also provided recent estimates for carbon flux based on forest ecosystem modeling.¹⁰² Carbon flux in Alaska's forests was modeled from 1950 through 2002. These carbon flux estimates are based on UAF's Terrestrial Ecosystem Model (TEM), which estimates net primary productivity for forest ecosystems and take into account carbon flux both forest biomass and soils. The effects of climate, fires, and CO₂ levels are evaluated within the modeling. Model runs were performed with and without the effects of fertilization from higher CO₂ levels. Figures H1a and b provide a summary of the modeling results.

The data shown in Figure H1a show the variation in carbon flux for all of Alaska's forests over the period of analysis. The average sequestration rate over the period of analysis is -10 MMtCO₂/yr and the range is from -94 to 143 MMtCO₂/yr (CCS converted the values in the figures from units of carbon to CO₂ to show these estimates). [Note: negative numbers used in this report represent sequestration; the only exception is Figures H1 and H2, where positive numbers were used in the UAF reports. Also, for this analysis, CCS reports the UAF modeling results for carbon flux without CO₂ fertilization effects for consistency with standard inventory approaches]. The large range in flux values is largely related to wildfire activity--years with net emissions are those where significant wildfire activity occurred. The summary statistics show that these data are negatively skewed, so the median value (-25 MMtCO₂/yr) is probably a better estimate of central tendency in the data.

Figure H1b shows similar estimates covering only the coastal maritime forests (primarily those in the Chugach and Tongass National Forests). Based on the mean and median of these annual estimates, the historical carbon flux for these forests has been about -1.2 to -1.3 MMtCO₂e/yr (as with the data for Figure H1a, CCS converted carbon to CO₂ to report these estimates).

¹⁰¹ Yarie, J. and S. Billings, "Carbon balance of the taiga forest within Alaska: present and future", *Canadian Journal of Forestry Research*, 32: 757-767 (2002).

¹⁰² D. McGuire and M. Balshi, UAF, personal communication and data file provided to S. Roe, CCS, January 2007. Documentation is included within a manuscript currently under review by the Journal of Geophysical Research.

Figure H1a. Statewide Forest Carbon Flux

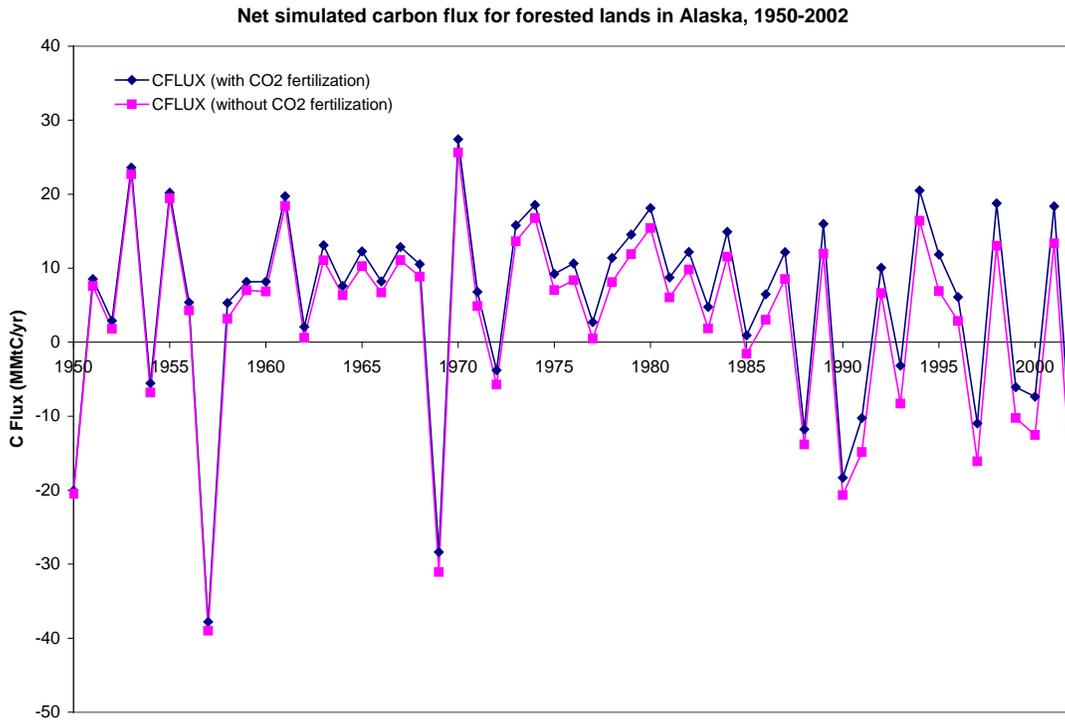
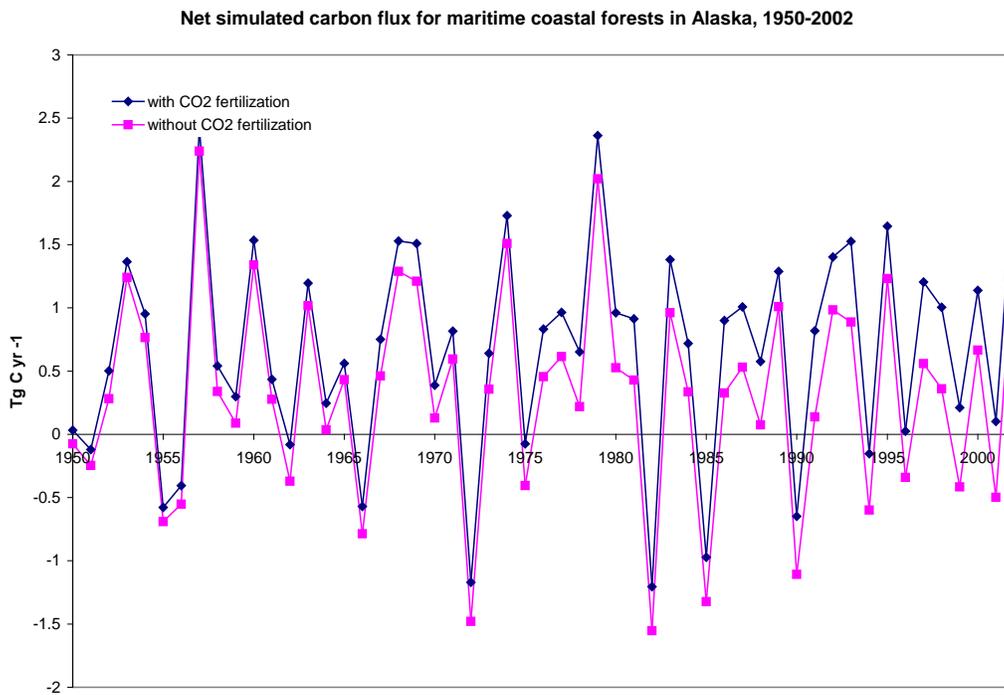


Figure H1b. Forest Carbon Flux in Coastal Maritime Forests



Note: Positive values in these graphs represent annual net sequestration. Source: M. Balshi, UAF, unpublished manuscript.

Figures H2a and b show the same modeling data from UAF as ten year averages of CO₂ sequestration in Alaska's forests. Ten year averages were selected to provide a comparison of sequestration rates in other western states.¹⁰³ An assessment of longer term averages also provides a sense of the sequestration potential of Alaskan forests during a typical year (a year that is not strongly influenced by large wildfire activity or no wildfire activity). The data in Figure H2a show that since the 1970s, average sequestration potential has decreased significantly. Historically, average sequestration rates were -20 to -30 MMtCO₂/yr. In recent decades, net sequestration has turned into net emissions of over 10 MMtCO₂/yr. Data for the 2000 time-frame were available through 2002. It appears that due to increased wildfire activity, Alaska's forests have entered into a period of net CO₂ emission during an average year.¹⁰⁴ Figure H3 provides ten year averages for statewide wildfire acres burned. The figure shows the upward trend in acres burned since the 1960's.¹⁰⁵

Figure H2b shows the ten year averages of CO₂e flux for coastal maritime forests. The data show that the net sequestration rates have stayed fairly constant over time, at around -1.4 MMtCO₂e/yr. According to UAF researchers, since there was no significant wildfire activity in the 1990's time-frame, the lower sequestration rates shown for that period are probably due to climate factors (additional analysis would be needed to confirm this and the specific factors involved).

The statewide results from UAF show a trend where the CO₂ sequestration rate approaches zero and transition to a net emission rate as a result of high fire activity. This finding is consistent with a 2006 study published in *Science*.¹⁰⁶ This study indicated an increasing frequency of wildfire activity in the western US since the mid-1980s driven by a longer fire season and higher average temperatures.

¹⁰³ In other western states assessed by CCS, the US Forest Service uses Forest Inventory and Analysis survey data to estimate carbon in forest carbon pools; the period between surveys is typically about 10 years. The ten year averages shown in Table H2 represent the 10 year period bracketing the year indicated (for example, the 1990 average is derived from the estimates for 1985-1994; 1995-2002 were used for the 2000 average).

¹⁰⁴ According to M. Balshi of UAF, the area burned during the period 2000-2005 (UAF simulations only go through 2002 due to climate data restraints) already exceeds that of every decade on record.

¹⁰⁵ S.K. Todd and H.A. Jewkes, *Wildland Fire in Alaska: A History of Organized Fire Suppression and Management in the Last Frontier*, Agricultural and Forestry Experiment Station Research Bulletin #114, University of Alaska, Fairbanks, March 2006. These rough estimates assume similar fuel loading/acre as used to develop the WRAP's 2002 fire estimates. As with the ten year carbon dioxide flux averages mentioned in the footnote above, CCS used 1985-1994 to represent the 1990 ten year average, etc. For the 2000 average, data for 1996-2004 were used.

¹⁰⁶ Westerling, A.L. et al, "Warming and Earlier Spring Increases Western US Forest Wildfire Activity", *Scienceexpress*, July 6, 2006.

Figure H2a. Ten-Year Average Forest CO₂ Flux in Statewide Forests

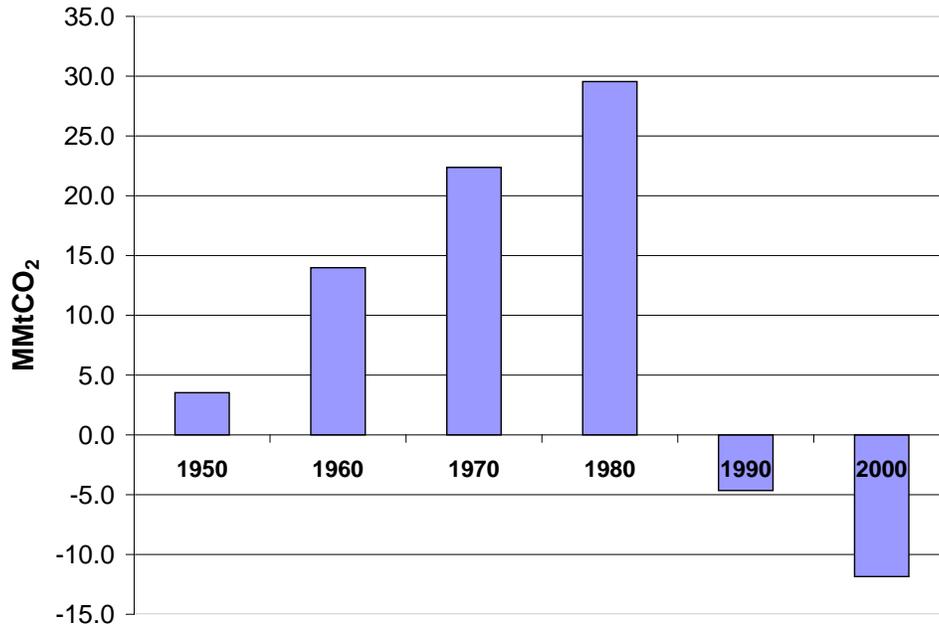
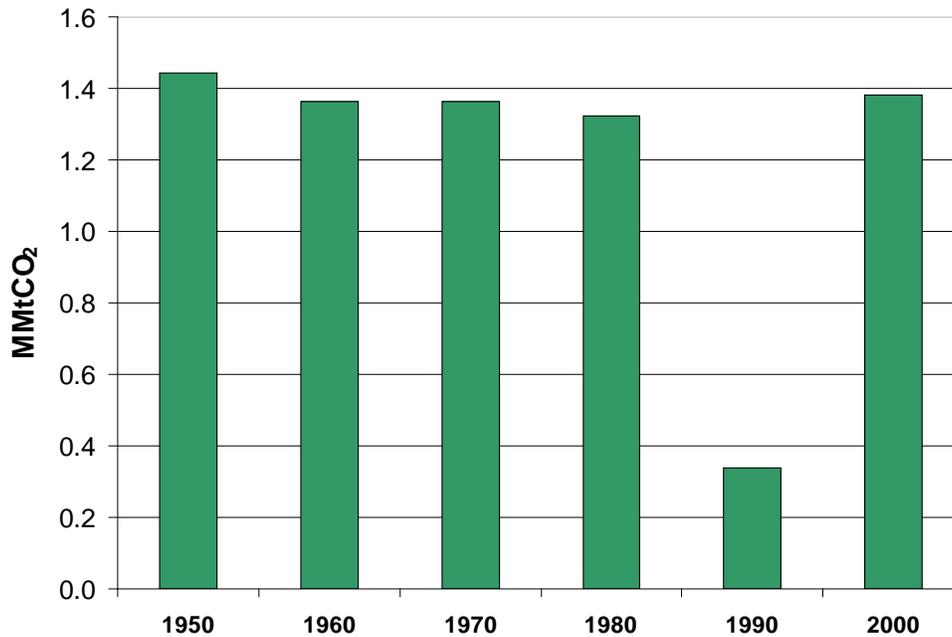
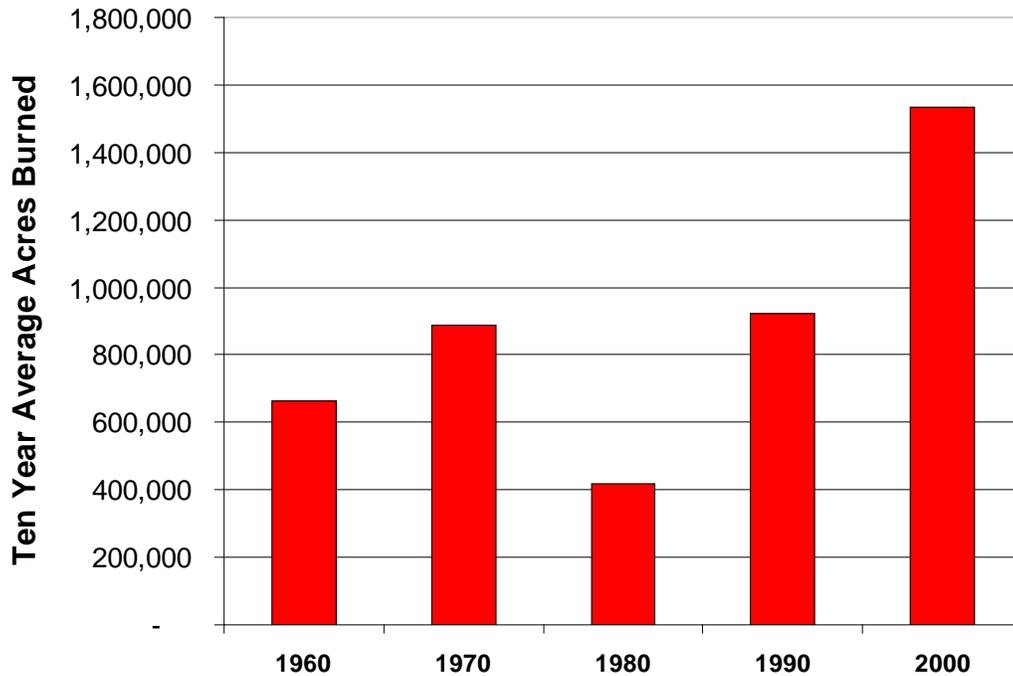


Figure H2b. Ten-Year Average Forest CO₂ Flux in Coastal Maritime Forests



Note: Positive values in these graphs represent annual net sequestration. Based on data from M. Balshi, UAF, unpublished manuscript.

Figure H3. Ten Year Averages of Statewide Wildfire Acres



Non-CO₂ Emissions from Wildfires

The UAF modeling of carbon flux described above included total carbon emissions, which would include CO₂, carbon monoxide, and methane (CH₄). In order to provide an estimate of CO₂e emissions for CH₄ and a more comprehensive understanding of GHG sources/sinks from the forestry sector, CCS developed rough estimates of state-wide emissions for methane (in CO₂ equivalents) and nitrous oxide (N₂O, in CO₂ equivalents) from wildfires and prescribed burns.¹⁰⁷ A separate estimate was also made for “managed” (coastal maritime) forests.

CCS used 2002 emissions data developed by the Western Regional Air Partnership (WRAP) to estimate CO₂e emissions for wildfires and prescribed burns.¹⁰⁸ The CO₂e from CH₄ emissions from this study were added to an estimate of CO₂e for N₂O to estimate a total CO₂e for fires. The nitrous oxide estimate was made assuming that N₂O was 1% of the emissions of nitrogen oxides (NO_x) from the WRAP study. The 1% estimate is a common rule of thumb for the N₂O content of NO_x from combustion sources.

The results for 2002 are that fires contributed 10.0 MMtCO₂e of CH₄ and NO_x from about 1.95 million acres burned (2002 was a fairly high wildfire activity year in Alaska and the western US). About 95% of the CO₂e was contributed by CH₄. For the purposes of comparison, another

¹⁰⁷ As with the CO₂ flux estimates for non-managed forests, the non-CO₂ emissions associated with fires on non-managed lands could also be considered non-anthropogenic (since wildfires are a natural occurrence). For the purposes of this study and for comparison to other state inventories prepared by CCS, these emissions are being provided at the state level as well as in “managed” forests.

¹⁰⁸ *2002 Fire Emission Inventory for the WRAP Region Phase I – Essential Documentation*, prepared by Air Sciences, Inc., June 2004.

2002 estimate was made using emission factors from a 2001 global biomass burning study¹⁰⁹ and the total tons of biomass burned from the 2002 WRAP fires emissions inventory. This estimate is about 11.8 MMtCO₂e showing good agreement with the estimate above; however, there were about equal contributions from methane and nitrous oxide on a CO₂e basis.

In order to estimate non-CO₂ GHG emissions for other years, CCS used wildfire acreage estimates for Alaska compiled in a recent report by UAF researchers.¹¹⁰ For years other than 2002, the emission estimate was made by multiplying the 2002 estimate described above (10 MMtCO₂e) by a ratio of the acres burned in each year to those burned in 2002. The fire acreages and emission estimates for 1985-2002 are presented in Table H1 below. For comparison to the CO₂ flux estimates, ten year averages are 4.7 MMtCO₂e/yr in 1990 and 4.9 MMtCO₂e/yr in 2000.¹¹¹

UAF provided wildfire acreage estimates for managed forests in each year. As was done to estimate the statewide emissions, the ratio of these acreages to the acreage for 2002 was used to estimate emissions of the non-CO₂ gases. There was very limited wildfire activity in the coastal maritime forests: about 500 acres in 1996; and about 1,500 acres in 2001.

Table H2 provides a summary of the CO₂ flux estimates for Alaska's forests. The table provides both a state-wide estimate as well as an estimate for managed forests in the state (coastal maritime forests). Estimates of managed forestlands are developed and used within this report of state-wide emissions to maintain consistency with IPCC guidelines for national GHG reporting. Additional explanatory notes are included at the end of this appendix. Post-2000 flux estimates are assumed to remain constant at the 2000 levels.

CH₄ Emissions from Alaskan Ecosystems

Alaska's ecosystems are expected to experience earlier and more drastic changes from global warming compared with lower latitude ecosystems.¹¹² The projected changes are consistent with changes that have been observed in recent decades, which include increases in mean annual air temperatures, thawing of permafrost, and longer growing seasons. Changes in climate, plant and soil conditions will have implications for CH₄ dynamics and carbon storage in Alaska's soils.

¹⁰⁹ M. O. Andreae and P. Merlet, "Emission of trace gases and aerosols from biomass burning", *Global Biogeochemical Cycles*, Vol. 15, No. 4, pp. 955-966, December 2001.

¹¹⁰ S.K. Todd and H.A. Jewkes, *Wildland Fire in Alaska: A History of Organized Fire Suppression and Management in the Last Frontier*, Agricultural and Forestry Experiment Station Research Bulletin #114, University of Alaska, Fairbanks, March 2006. These rough estimates assume similar fuel loading/acre as used to develop the WRAP's 2002 fire estimates.

¹¹¹ The ten year average stated for 2000 is based on data from 1995-2002. If data through 2004 were available, the estimated emissions would be larger due to high fire activity through 2004.

¹¹² Zhuang, Q., J. M. Melillo, A.D. McGuire, D.W. Kicklighter, R.G. Prinn, P.A. Steudler, B.S. Felzer, and S. Hu. 2007. "Net land-atmosphere exchanges of CH₄ and CO₂ in Alaska: Implications for the region's greenhouse gas budget", *Ecological Applications*, in press.

Table H1. Statewide Non-CO₂ GHG Emissions Estimates from Wildfires

Year	Acreage	Non-CO ₂ Emissions (MMtCO ₂ e)	Year	Acreage	Non-CO ₂ Emissions (MMtCO ₂ e)
1985	407,300	2.1	1994	265,722	1.4
1986	477,455	2.4	1995	43,946	0.2
1987	169,145	0.9	1996	599,267	3.1
1988	2,134,539	11	1997	2,026,899	10
1989	64,810	0.3	1998	120,752	0.6
1990	3,189,078	16	1999	1,005,427	5.2
1991	1,667,950	8.6	2000	756,296	3.9
1992	150,006	0.8	2001	216,039	1.1
1993	712,869	3.7	2002	1,950,000 ^a	10 ^a

^a Acreage and emissions estimates based on the WRAP's 2002 Fire Inventory.

Table H2. Forestry CO₂e Flux Estimates for Alaska

Source	CO ₂ e Flux (MMtCO ₂ e) ^a				
	1990	2000	2005	2010	2020
<i>State-Level Forest Flux</i>					
CO ₂ Flux	4.6	12	12	12	12
Non-CO ₂ Gases from Fire	4.5	4.9	4.9	4.9	4.9
CH ₄ Flux ^b	16	21	24	26	31
Total State-Level	25	38	41	43	48
<i>Flux for Managed Forests^c</i>					
CO ₂ Flux	-0.3	-1.4	-1.4	-1.4	-1.4
Non-CO ₂ Gases from Fire	0.0	<0.01	<0.01	<0.01	<0.01
CH ₄ Flux	n/a	n/a	n/a	n/a	n/a
Total – Managed Forests	-0.3	-1.4	-1.4	-1.4	-1.4

Positive values represent net CO₂e emissions. Non-CO₂ gases are methane and nitrous oxide.
^a Values reported are ten year averages of annual data surrounding the year reported (e.g., 1990 average is the average of data for 1985-1994). For 2000, data only available through 2002. After 2000, flux estimates are assumed to remain constant.
^b UAF estimate for the 1980-1996 period used for 1990. UAF growth rate of 0.5 MMtCO₂e/yr used for forecast years. See Section on CH₄ emissions from Alaskan ecosystems.
^c Managed forests are the coastal maritime forests of the state. CH₄ flux estimates were not available for managed forests.

Further, according to UAF researchers, one-third of the global soil carbon stocks are located in the Arctic. The fate of this stored soil carbon under altered climate is a major question, since microbes can respond quickly to temperature changes in high latitude ecosystems. Soil microbial activity includes organic matter decomposition under aerobic conditions that releases CO₂ to the atmosphere. Under anaerobic conditions, warming and changes in hydrology could trigger rapid CH₄ emissions in response to the early spring thawing in sub-arctic mire ecosystems. Methane dynamics are also influenced by the increase in the depth to which permafrost thaws each summer and any changes in the water table of northern peatlands that may result from changes in the water cycle. While CH₄ flux is considered to be non-anthropogenic, estimates are provided in this appendix for information purposes, given the influence of climate change.

UAF has conducted studies using its TEM model of CH₄ flux from Taiga (interior forests) and Tundra (treeless) ecosystems in Alaska. These ecosystems are estimated to be net sources of CH₄. Net emissions of 3.1 MMtCH₄/yr (65 MMtCO₂e/yr) estimated for the period of 1980-1996 are expected to almost double to 5.7 MMtCH₄/yr (120 MMtCO₂e/yr) by the 2080-2099 period. The growth rate in emissions is estimated at 0.026 MMtCH₄/yr (0.5 MMtCO₂e/yr). Of the 3.1 MMtCH₄/yr emitted in the 1980-1996 period, 0.76 MMtCH₄/yr is emitted in the Taiga ecosystem (16 MMtCO₂e/yr). These estimates were incorporated into the statewide estimates presented in Table H2. Note that these emissions do not include the previously-described CH₄ emissions that occur as a result of fire. No data were available for methane flux from coastal forest ecosystems.

Key Uncertainties

Both the estimates of forest CO₂e flux and ecosystem CH₄ flux presented here should be viewed as preliminary estimates based on process-based modeling of Alaska's ecosystems. For CH₄ flux, UAF comparisons against site-specific measurements suggest that the uncertainty around the flux estimate is probably plus or minus 50% overall. As described above, from year to year, CO₂ flux in forested lands varies dramatically depending on the level of wildfire activity. Years with high wildfire activity result in large net emissions of CO₂ to the atmosphere, while, in years with low activity, a significant level of CO₂ sequestration occurs. To provide a better sense of changes that are occurring in net carbon flux over time as well as a data set for comparison to other states, CCS has provided results in ten year averages.

The issue of what constitutes managed forests in Alaska may need further consideration and refinement (see additional notes on this issue from IPCC guidance below). Although fire suppression has occurred throughout state forests in previous decades, it is questionable whether the level of suppression was significant enough to designate much of the State's forests to be "managed". For the purposes of this initial assessment, CCS assumed that managed forests are those in the coastal maritime forests of Alaska (primarily those in the Chugach and Tongass National Forests). These coastal forests have much different net CO₂ flux from Alaska's interior forests (due to both sequestration potential and fire occurrence). It is possible that some of the interior forests have received sufficient intervention to be considered managed forests (e.g., those surrounding communities, productive forests).

CCS estimates that the estimates that uncertainty in the non-CO₂ emissions from wildfires is +/- a factor of two. This is based on comparisons with estimates in a recent paper from French et al on the uncertainty in GHG emissions from boreal forests.¹¹³ The estimates provided here for non-CO₂ data made by extrapolating the WRAP's 2002 fire estimates are higher than those reported in this study by over a factor of two. One primary difference is that the estimates reported here include N₂O, while the French et al paper included carbon-containing compounds only. There is a lot of uncertainty specifically on the issue of N₂O emissions from wildfires; however it could contribute substantially to the total CO₂e emissions for fires. The other main issues are the emission factors used in either the WRAP or French et al study for methane, as well as fuel loading factors, handling of emissions from different phases of wildfires (especially

¹¹³ French, N.H.F., P. Goovaerts, E.S. Kasichke, "Uncertainty in estimating carbon emissions from boreal forest fires", *Journal of Geophysical Research*, vol. 19, D14S08, 2004.

smoldering), and possibly other factors. A more in-depth analysis of the differences in these studies was beyond the scope of this initial assessment.

Forecasting of forest carbon flux is particularly challenging. UAF is currently engaged in developing forecasts of carbon flux, and these data should be reviewed for incorporation when available. Although the statewide trend appears to be moving in the direction of increased CO₂e emissions, the sequestration rates in the managed forests have remained fairly constant over time. For the purposes of this assessment, CCS assumes that the flux rates will stay constant at the 2000 levels.

Additional Notes: IPCC Guidelines for Agriculture, Forestry, and Other Land Uses (AFOLU)

The AFOLU Sector has some unique characteristics with respect to developing inventory methods. There are many processes leading to emissions and removals of greenhouse gases, which can be widely-dispersed in space and highly variable in time. The factors governing emissions and removals can be both natural and anthropogenic (direct and indirect) and it can be difficult to clearly distinguish between causal factors. While recognizing this complexity, inventory methods need to be practical and operational. The 2006 IPCC Guidelines are designed to assist in estimating and reporting national inventories of anthropogenic greenhouse gas emissions and removals. For the AFOLU Sector, anthropogenic greenhouse gas emissions and removals by sinks are defined as all those occurring on 'managed land'. Managed land is land where human interventions and practices have been applied to perform production, ecological or social functions. All land definitions and classifications should be specified at the national level, described in a transparent manner, and be applied consistently over time. Emissions/removals of greenhouse gases do not need to be reported for unmanaged land. However, it is good practice for countries to quantify, and track over time, the area of unmanaged land so that consistency in area accounting is maintained as land-use change occurs.

The use of managed land as a proxy for anthropogenic effects is in use in the present IPCC guidelines. The key rationale for this approach is that the preponderance of anthropogenic effects occurs on managed lands. By definition, all direct human-induced effects on greenhouse gas emissions and removals occur on managed lands only. While it is recognized that no area of the Earth's surface is entirely free of human influence (e.g., CO₂ fertilization), many indirect human influences on greenhouse gases (e.g., increased N deposition, accidental fire) will be manifested predominately on managed lands, where human activities are concentrated. Finally, while local and short-term variability in emissions and removals due to natural causes can be substantial (e.g., emissions from fire), the natural 'background' of greenhouse gas emissions and removals by sinks tends to average out over time and space. This leaves the greenhouse gas emissions and removals from managed lands as the dominant result of human activity.

Specific Guidance for Forests: Countries should consistently apply national definitions of managed forests over time. National definitions should cover all forests subject to human intervention, including the full range of management practices from protecting forests, raising plantations, promoting natural regeneration, commercial timber production, non-commercial fuel wood extraction, and abandonment of managed land.

Appendix I. Inventory and Forecast for Black Carbon

This appendix summarizes the methods, data sources, and results of the development of an inventory and forecast for black carbon (BC) emissions in Alaska. Black carbon is an aerosol (particulate matter or PM) species with positive climate forcing potential but currently without a global warming potential defined by the IPCC (see Appendix J for more information on BC and other aerosol species). BC is synonymous with elemental carbon (EC), which is a term common to regional haze analysis. An inventory for 2002 was developed based on inventory data from the Western Regional Air Partnership (WRAP) regional planning organization and other sources.¹¹⁴ This appendix describes these data and methods for estimating mass emissions of BC and then transforming the mass emission estimates into CO₂e equivalents (CO₂e) in order to present the emissions within a GHG context.

In addition to the PM inventory data from WRAP, PM speciation data from EPA's SPECIATE database were also used: these data include PM fractions of EC (also known as BC) and primary organic aerosols (also known as organic material, or OM). These data come from the US Environmental Protection Agency's latest release of its SPECIATE database (Version 4.0).¹¹⁵ As will be further described below, both BC and OM emission estimates are needed to assess the CO₂e of BC emissions. While BC and OM emissions data are available from the WRAP regional haze inventories, CCS favored the newer speciation data available from EPA for the purposes of estimating BC and OM for most source sectors (BC and OM data from the WRAP were used only for the nonroad engines sector). In particular, better speciation data are now available from EPA for important BC emissions sources (including most fossil fuel combustion sources).

After assembling the BC and OM emission estimates, the mass emission rates were transformed into their CO₂e estimates using information from recent global climate modeling. This transformation is described in later sections below.

Development of BC and OM Mass Emission Estimates

The BC and OM mass emission estimates were derived by multiplying the emissions estimates for particulate matter with an aerodynamic diameter of less than 2.5 micrometers (PM_{2.5}) by the appropriate aerosol fraction for BC and OM. The aerosol fractions were taken from Pechan's ongoing work to update EPA's SPECIATE database as approved by EPA's SPECIATE Workgroup members.

After estimating both BC and OM emissions for each source category, we used the BC estimate as described below to estimate the CO₂e emissions. Also, as described further below, the OM emission estimate was used to determine whether the source was likely to have positive climate forcing potential. The mass emission results for 2002 are shown in Table I1.

¹¹⁴ Tom Moore, Western Regional Air Partnership, data files provided to Steve Roe, CCS, December 2006; Corbett, J., *Estimation, Validation, and Forecasts of Regional Commercial Marine Vessel Emissions, Tasks 1 and 2: Baseline Inventory and Ports Comparison, Final Report*, May 3, 2006.

¹¹⁵ US EPA, Version 4.0 of the SPECIATE database and report, released January 2007:
<http://www.epa.gov/ttn/chief/software/speciate/index.html#related>.

Development of CO_{2e} for BC+OM Emissions

We used similar methods to those applied previously in Maine and Connecticut for converting BC mass emissions to CO_{2e}.¹¹⁶ These methods are based on the modeling of Jacobson (2002)¹¹⁷ and his updates to this work (Jacobson, 2005a).¹¹⁸ Jacobson (2005a) estimated a range of 90:1 to 190:1 for the climate response effects of BC+OM emissions as compared to CO₂ carbon emissions (depending on either a 30-year or 95-year atmospheric lifetime for CO₂). It is important to note that the BC+OM emissions used by Jacobson were based on a 2:1 ratio of OM:BC (his work in these papers focused on fossil fuel BC+OM; primarily diesel combustion, which has an OM:BC ratio of 2:1 or less).

For Maine and Connecticut, ENE (2004) applied climate response factors from the earlier Jacobson work (220 and 500) to the estimated BC mass to estimate the range of CO_{2e} associated with BC emissions. Note that the analysis in the northeast was limited to BC emissions from onroad diesel exhaust. An important oversight from this work is that the climate response factors developed by Jacobson (2002, 2005a) are on the basis of CO₂ carbon (not CO_{2e}). Therefore, in order to express the BC emissions as CO_{2e}, the climate response factors should have been adjusted upward by a factor of 3.67 to account for the molecular weight of CO₂ to carbon (44/12).

For this inventory, we started with the 90 and 190 climate response factors adjusted to CO_{2e} factors of 330 and 697 to obtain a low and high estimate of CO_{2e} for each sector. An example calculation of the CO_{2e} emissions for 10 tons of PM less than 2.5 microns (PM_{2.5}) from onroad diesel exhaust follows:

$$\text{BC mass} = (10 \text{ short tons PM}_{2.5}) \times (0.613 \text{ ton EC/ton PM}_{2.5}) = 6.13 \text{ short tons BC}$$

$$\text{Low estimate CO}_{2e} = (6.13 \text{ tons BC}) (330 \text{ tons CO}_{2e}/\text{ton BC+OM}) (3 \text{ tons BC+OM/ton BC}) (0.907 \text{ metric ton/ton}) = 5,504 \text{ metric tons CO}_{2e}$$

$$\text{High estimate CO}_{2e} = (6.13 \text{ tons BC}) (697 \text{ tons CO}_{2e}/\text{ton BC+OM}) (3 \text{ tons BC+OM/ton BC}) (0.907 \text{ metric ton/ton}) = 11,626 \text{ metric tons CO}_{2e}$$

NOTE: The factor 3 tons BC+OM/ton BC comes directly from the global modeling inputs used by Jacobson (2002, 2005a; i.e., 2 tons of OM/ton of BC).

¹¹⁶ ENE, 2004. Memorandum: "Diesel Black Carbon Calculations – Reductions and Baseline" from Michael Stoddard, Environment Northeast, prepared for the Connecticut Stakeholder Dialog, Transportation Work Group, October 23, 2003.

¹¹⁷ Jacobson, 2002. Jacobson, M.Z., "Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming", *Journal of Geophysical Physical Research*, volume 107, No. D19, 4410, 2002.

¹¹⁸ Jacobson, 2005a. Jacobson, M.Z., "Updates to 'Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming'", *Journal of Geophysical Research Atmospheres*, February 15, 2005.

For source categories that had an OM:BC mass emissions ratio >4.0 , we zeroed out these emission estimates from the CO₂e estimates. The reason for this is that the net heating effects of OM are not currently well understood (overall OM is thought to have a negative climate forcing effect or a net cooling effect). Therefore, for source categories where the PM is dominated by OM (e.g., biomass burning), the net climate response associated with these emissions is highly uncertain and could potentially produce a net negative climate forcing potential. Further, OM:BC ratios of 4 or more are well beyond the 2:1 ratio used by Jacobson in his work.

Results and Discussion

We estimate that BC mass emissions in Alaska total about 3.0 MMtCO₂e in 2002. This is the mid-point of the estimated range of emissions. The estimated range is 1.9 – 4.0 MMtCO₂e (see Table I1). The primary contributing sectors in 2002 were commercial marine vessels (37%)¹¹⁹, aircraft (14%), nonroad diesel (12%), onroad diesel (8%), residential/commercial/industrial (RCI) coal combustion (6%), electricity generating unit (EGU) oil combustion (6%), nonroad gasoline engines (5%), RCI “other” combustion (mainly large diesel engines; 4%), and EGU coal combustion (4%).

The nonroad diesel sector includes exhaust emissions from construction/mining, industrial and agricultural engines, as well as recreational equipment. Construction and mining engines contributed about 72% of the diesel nonroad total, while the rest of the emissions were spread across remaining engine categories. For nonroad gasoline engines, 64% of the emissions were contributed by recreational equipment, and the remaining emissions were spread across the remaining engine categories.

Wildfires and miscellaneous sources such as fugitive dust from paved and unpaved roads contributed a significant amount of PM and subsequent BC and OM mass emissions (see Table I1); however the OM:BC ratio is >4 for these sources, so the BC emissions were not converted to CO₂e.

CCS also performed an assessment of the primary BC contributing sectors from the 2018 WRAP forecast. A drop in the future BC emissions for the onroad and nonoad diesel sectors is expected due to new engine and fuels standards that will reduce particulate matter emissions. For the nonroad diesel sector the estimated 0.3 MMtCO₂e in 2002 drops to 0.09 MMtCO₂e in 2018. For the onroad diesel sector, 0.2 MMtCO₂e was estimated for 2002 dropping to 0.03 MMtCO₂e in 2018 (Note: as with the other estimates described above, these represent the mid-point in the estimated range of emissions). No significant reductions are expected in the other emission sectors. The development of emission estimates for the remaining source sectors was beyond the scope of this analysis.

¹¹⁹ Particulate matter emissions, from the Corbett et al (2006) study referenced in the footnote above, were used as the starting point for estimating CMV emissions. These include in-port as well as underway emissions within 200 miles from shore (the Exclusive Economic Zone). The BC and OM fractions from the same speciation profiles used in the WRAP inventory (also referenced above) were applied to estimate BC and OM mass emissions, which were then transformed into their CO₂ equivalents.

While the state of science in aerosol climate forcing is still developing, there is a good body of evidence supporting the net warming impacts of BC. Aerosols have a *direct* radiative forcing because they scatter and absorb solar and infrared radiation in the atmosphere. Aerosols also alter the formation and precipitation efficiency of liquid water, ice and mixed-phase clouds, thereby causing an *indirect* radiative forcing associated with these changes in cloud properties (IPCC, 2001).¹²⁰ There are also a number of other indirect radiative effects that have been modeled (see, for example, Jacobson, 2002, as noted in the footnote of the previous page).

The quantification of aerosol radiative forcing is more complex than the quantification of radiative forcing by GHGs because of the direct and indirect radiative forcing effects, and the fact that aerosol mass and particle number concentrations are highly variable in space and time. This variability is largely due to the much shorter atmospheric lifetime of aerosols compared with the important GHGs (i.e., CO₂). Spatially and temporally resolved information on the atmospheric concentration and radiative properties of aerosols is needed to estimate radiative forcing.

The quantification of indirect radiative forcing by aerosols is especially difficult. In addition to the variability in aerosol concentrations, some complicated aerosol influences on cloud processes must be accurately modeled. For example, the warm (liquid water) cloud indirect forcing may be divided into two components. The first indirect forcing is associated with the change in droplet concentration caused by increases in aerosol cloud condensation nuclei. The second indirect forcing is associated with the change in precipitation efficiency that results from a change in droplet number concentration. Quantification of the latter forcing necessitates understanding of a change in cloud liquid-water content. In addition to warm clouds, ice clouds may also be affected by aerosols.

To put the radiative forcing potential of BC in context with CO₂, the IPCC estimated the radiative forcing for a doubling of the earth's CO₂ concentration to be 3.7 watts per square meter (W/m²). For BC, various estimates of current radiative forcing have ranged from 0.16 to 0.42 W/m² (IPCC, 2001). These BC estimates are for direct radiative effects only. There is a higher level of uncertainty associated with the direct radiative forcing estimates of BC compared to those of CO₂ and other GHGs. There are even higher uncertainties associated with the assessment of the indirect radiative forcing of aerosols.

¹²⁰ IPCC, 2001. Climate Change 2001: The Scientific Basis, Intergovernmental Panel on Climate Change, 2001.

Table I1. 2002 BC Emission Estimates

Sector	Subsector	Mass Emissions			CO ₂ Equivalents		Contribution to CO ₂ e (%)
		BC	OM	BC + OM	Low	High	
		Metric Tons			Metric Tons		
Electric Generating Units (EGUs)	Coal	79	113	191	78,045	164,841	4.1
	Oil	109	37	146	107,709	227,494	5.6
	Gas	0	168	168	0	0	0.0
	Other ^a	30	10	40	29,972	63,304	1.6
Non-EGU Fuel Combustion (Residential, Commercial, and Industrial)							
	Coal	120	172	292	118,955	251,247	6.2
	Oil	14	8	22	14,085	29,750	0.7
	Gas	0	1,501	1,501	0	0	0.0
	Other ^a	318	1,194	1,512	81,499	172,136	4.3
	Onroad Gasoline (Exhaust, Brake Wear, & Tire Wear)	17	65	81	7,048	14,886	0.4
	Onroad Diesel (Exhaust, Brake Wear, & Tire Wear)	161	67	228	143,337	302,745	7.5
	Aircraft	272	354	627	269,392	568,988	14.1
	Railroad ^b	27	9	35	26,288	55,523	1.4
	Commercial Marine Vessels	721	234	955	713,790	1,507,611	37.3
Other Energy Use	Nonroad Gas	101	284	385	99,983	211,176	5.2
	Nonroad Diesel	222	56	279	220,187	465,061	11.5
	Other Combustion ^c	0	4	4	0	0	0.0
Industrial Processes		1	42	43	0	0	0.0
Agriculture ^d		2	205	207	0	0	0.0
Waste Management	Landfills	0	0	0			0.0
	Incineration	1	1	2	1,071	2,262	0.1
	Open Burning	35	455	490	0	0	0.0
	Other	0	0	0			0.0
Wildfires/Prescribed Burns		49,185	494,471	543,655	0	0	0.0
Miscellaneous ^e		18	294	312	0	0	0.0
Total		51,434	499,742	551,176	1,911,360	4,037,023	100

^a Primarily large stationary diesel engines/turbines.

^b Railroad includes Locomotives and Railroad Equipment Emissions.

^c Other Combustion includes Motor Vehicle Fire, Structure Fire, and Aircraft/Rocket Engine Fire & Testing Emissions.

^d Agriculture includes Agricultural Burning, Agriculture/Forestry and Agriculture, Food, & Kindred Spirits Emissions.

^e Miscellaneous includes Paved/Unpaved Roads and Catastrophic/Accidental Release Emissions.

Appendix J. Greenhouse Gases and Global Warming Potential Values: Excerpts from the *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2000*

Original Reference: Material for this Appendix is taken from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2000*, U.S. Environmental Protection Agency, Office of Atmospheric Programs, EPA 430-R-02-003, April 2002 (www.epa.gov/globalwarming/publications/emissions). Michael Gillenwater directed the preparation of this appendix.

Introduction

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and removals for the years 1990 through 2000. The estimates 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.

The Intergovernmental Panel on Climate Change (IPCC) has recently updated the specific global warming potentials for most greenhouse gases in their Third Assessment Report (TAR, IPCC 2001). Although the GWPs have been updated, estimates of emissions presented in the U.S. *Inventory* continue to use the GWPs from the Second Assessment Report (SAR). The guidelines under which the *Inventory* is developed, the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) and the United Nations Framework Convention on Climate Change (UNFCCC) reporting guidelines for national inventories¹²¹ were developed prior to the publication of the TAR. Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. This excerpt of the U.S. *Inventory* addresses in detail the differences between emission estimates using these two sets of GWPs. Overall, these revisions to GWP values do not have a significant effect on U.S. emission trends.

Additional discussion on emission trends for the United States can be found in the complete *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*.

What is Climate Change?

Climate change refers to long-term fluctuations in temperature, precipitation, wind, and other elements of the Earth's climate system. Natural processes such as solar-irradiance variations, variations in the Earth's orbital parameters, and volcanic activity can produce variations in climate. The climate system can also be influenced by changes in the concentration of various gases in the atmosphere, which affect the Earth's absorption of radiation.

The Earth naturally absorbs and reflects incoming solar radiation and emits longer wavelength terrestrial (thermal) radiation back into space. On average, the absorbed solar radiation is balanced by the outgoing terrestrial radiation emitted to space. A portion of this terrestrial radiation, though, is itself absorbed by gases in the atmosphere. The energy from this absorbed terrestrial radiation warms the Earth's surface and atmosphere, creating what is known as the "natural greenhouse effect." Without the natural heat-trapping properties of these atmospheric gases, the average surface temperature of the Earth would be about 33°C lower (IPCC 2001).

Under the UNFCCC, the definition of climate change is "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in

¹²¹ See FCCC/CP/1999/7 at <www.unfccc.de>.

addition to natural climate variability observed over comparable time periods.” Given that definition, in its Second Assessment Report of the science of climate change, the IPCC concluded that:

Human activities are changing the atmospheric concentrations and distributions of greenhouse gases and aerosols. These changes can produce a radiative forcing by changing either the reflection or absorption of solar radiation, or the emission and absorption of terrestrial radiation (IPCC 1996).

Building on that conclusion, the more recent IPCC Third Assessment Report asserts that “[c]oncentrations of atmospheric greenhouse gases and their radiative forcing have continued to increase as a result of human activities” (IPCC 2001).

The IPCC went on to report that the global average surface temperature of the Earth has increased by between $0.6 \pm 0.2^{\circ}\text{C}$ over the 20th century (IPCC 2001). This value is about 0.15°C larger than that estimated by the Second Assessment Report, which reported for the period up to 1994, “owing to the relatively high temperatures of the additional years (1995 to 2000) and improved methods of processing the data” (IPCC 2001).

While the Second Assessment Report concluded, “the balance of evidence suggests that there is a discernible human influence on global climate,” the Third Assessment Report states the influence of human activities on climate in even starker terms. It concludes that, “[I]n light of new evidence and taking into account the remaining uncertainties, most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas concentrations” (IPCC 2001).

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, and other trace gases in the atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 1996). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans. A gauge of these changes is called radiative forcing, which is a simple measure of changes in the energy available to the Earth-atmosphere system (IPCC 1996). 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, 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). Because CFCs, HCFCs, and halons are stratospheric ozone depleting substances, they are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty; consequently these gases are not included in national greenhouse gas inventories. 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—referred to as ambient

air pollutants—include carbon monoxide (CO), nitrogen dioxide (NO₂), sulfur dioxide (SO₂), and tropospheric (ground level) ozone (O₃). 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—extremely small particles or liquid droplets—often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants—can affect the absorptive characteristics of the atmosphere. However, the level of scientific understanding of aerosols is still very low (IPCC 2001).

Carbon dioxide, methane, and nitrous oxide 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 10.

Table 10. Global Atmospheric Concentration (ppm Unless Otherwise Specified), Rate of Concentration Change (ppb/year) and Atmospheric Lifetime (Years) of Selected Greenhouse Gases

Atmospheric Variable	CO ₂	CH ₄	N ₂ O	SF ₆ ^a	CF ₄ ^a
Pre-industrial atmospheric concentration	278	0.700	0.270	0	40
Atmospheric concentration (1998)	365	1.745	0.314	4.2	80
Rate of concentration change ^b	1.5 ^c	0.007 ^c	0.0008	0.24	1.0
Atmospheric Lifetime	50-200 ^d	12 ^e	114 ^e	3,200	>50,000

Source: IPCC (2001)

^a Concentrations in parts per trillion (ppt) and rate of concentration change in ppt/year.

^b Rate is calculated over the period 1990 to 1999.

^c Rate has fluctuated between 0.9 and 2.8 ppm per year for CO₂ and between 0 and 0.013 ppm per year for CH₄ over the period 1990 to 1999.

^d No single lifetime can be defined for CO₂ 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 Global Warming Potentials (GWPs), which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H₂O). 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 directly affect the average global concentration of water vapor; however, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. A warmer atmosphere has an increased water holding capacity; yet, 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 (CO₂). 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 CO₂. Atmospheric carbon dioxide is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Carbon dioxide concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 367 ppmv in 1999, a 31 percent increase (IPCC 2001). The IPCC notes that “[t]his concentration has not been exceeded during the past 420,000 years, and likely not during the past 20 million years. The rate of increase over the past century is unprecedented, at least during the past 20,000 years.” The IPCC definitively states that “the present atmospheric CO₂ increase is caused by anthropogenic emissions of CO₂” (IPCC 2001). Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of carbon dioxide.

In its second assessment, the IPCC also stated that “[t]he increased amount of carbon dioxide [in the atmosphere] is leading to climate change and will produce, on average, a global warming of the Earth’s surface because of its enhanced greenhouse effect—although the magnitude and significance of the effects are not fully resolved” (IPCC 1996).

Methane (CH₄). Methane 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 CH₄, as does the decomposition of municipal solid wastes. Methane 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 methane have increased by about 150 percent since pre-industrial times, although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH₄ flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use and waste disposal (IPCC 2001).

Methane is removed from the atmosphere by reacting with the hydroxyl radical (OH) and is ultimately converted to CO₂. Minor removal processes also include reaction with Cl in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of methane reduce the concentration of OH, a feedback which may increase methane’s atmospheric lifetime (IPCC 2001).

Nitrous Oxide (N₂O). Anthropogenic sources of N₂O emissions include agricultural soils, especially the use of synthetic and manure fertilizers; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste combustion; and biomass burning. The atmospheric concentration of nitrous oxide (N₂O) has increased by 16 percent since 1750, from a pre industrial value of about 270 ppb to 314 ppb in 1998, a concentration that has not been exceeded during the last thousand years. Nitrous oxide is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere.

Ozone (O₃). Ozone is present in both the upper stratosphere, where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere, 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 chlorofluorocarbons (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, with detection of such recovery not expected to occur much before 2010 (IPCC 2001).

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 CO₂ and CH₄. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds mixing with nitrogen oxides (NO_x) in the presence of sunlight. Ozone, carbon monoxide (CO), sulfur dioxide (SO₂), nitrogen dioxide (NO₂) and particulate matter are included in the category referred to as “criteria pollutants” in the United States under the Clean Air Act and its subsequent amendments. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable.

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride (SF₆). Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine—chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), methyl chloroform, and carbon tetrachloride—and bromine—halons, methyl bromide, and hydrobromofluorocarbons (HBFCs)—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 is itself 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 countries beginning in 1996, and then followed by a complete phase-out by the year 2030. The ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC.

Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆) are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs—primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process—currently have a small aggregate radiative forcing impact; however, it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2001). PFCs and SF₆ are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium casting. Currently, the radiative forcing impact of PFCs and SF₆ is also small; however, 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 (CO). Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH₄ and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH₄ 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 CO₂. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides (NO_x). The primary climate change effects of nitrogen oxides (i.e., NO and NO₂) 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. Additionally, NO_x emissions from aircraft are also likely to decrease methane 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 nitrous oxide (N₂O). Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Nonmethane volatile organic compounds include compounds 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. They affect radiative forcing in both direct and indirect ways: directly by scattering and absorbing solar and thermal infrared 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, sulphates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols is believed to produce a negative radiative forcing effect (i.e., net cooling effect on the climate), although because they are short-lived in the atmosphere—lasting days to weeks—their concentrations respond rapidly to changes in emissions. 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 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, elemental carbon, may have a positive radiative forcing (Jacobson 2001). The primary anthropogenic emission sources of elemental carbon include diesel exhaust, coal combustion, and biomass burning.

Global Warming Potentials

Global Warming Potentials (GWPs) are intended as a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas. It is defined as the cumulative radiative forcing—both direct and indirect effects—integrated over a period of time from the emission of a unit mass of gas relative to some reference gas (IPCC 1996). Carbon dioxide (CO₂) was chosen as this reference gas. Direct effects occur when the gas itself is a greenhouse gas. 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 relationship between gigagrams (Gg) of a gas and Tg CO₂ 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 CO₂ Eq. = Teragrams of Carbon Dioxide Equivalents
Gg = Gigagrams (equivalent to a thousand metric tons)
GWP = Global Warming Potential
Tg = Teragrams

GWP values allow policy makers to compare the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of roughly ±35 percent, though some GWPs have larger uncertainty than others, especially those in which lifetimes have not yet been ascertained. In the following decision, the parties to the UNFCCC have agreed to use consistent GWPs from the IPCC Second Assessment Report (SAR), based upon a 100 year time horizon, although other time horizon values are available (see Table 11).

In addition to communicating emissions in units of mass, Parties may choose also to use global warming potentials (GWPs) to reflect their inventories and projections in carbon dioxide-equivalent terms, using information provided by the Intergovernmental Panel on Climate Change (IPCC) in its Second Assessment Report. Any use of GWPs should be based on the effects of the greenhouse gases over a 100-year time horizon. In addition, Parties may also use other time horizons. (FCCC/CP/1996/15/Add.1)

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆) 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, other ambient air pollutants (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO₂ products and black carbon), however, vary spatially, and consequently it is difficult to quantify their global radiative forcing impacts. GWP values are generally not attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 11. Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years) Used in the Inventory

Gas	Atmospheric Lifetime	100-year GWP ^a	20-year GWP	500-year GWP
Carbon dioxide (CO ₂)	50-200	1	1	1
Methane (CH ₄) ^b	12±3	21	56	6.5
Nitrous oxide (N ₂ O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800
HFC-125	32.6	2,800	4,600	920
HFC-134a	14.6	1,300	3,400	420
HFC-143a	48.3	3,800	5,000	1,400
HFC-152a	1.5	140	460	42
HFC-227ea	36.5	2,900	4,300	950
HFC-236fa	209	6,300	5,100	4,700
HFC-4310mee	17.1	1,300	3,000	400
CF ₄	50,000	6,500	4,400	10,000
C ₂ F ₆	10,000	9,200	6,200	14,000
C ₄ F ₁₀	2,600	7,000	4,800	10,100
C ₆ F ₁₄	3,200	7,400	5,000	10,700
SF ₆	3,200	23,900	16,300	34,900

Source: IPCC (1996)

^a GWPs used here are calculated over 100 year time horizon

^b The methane 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 CO₂ is not included.

Table 12 presents direct and net (i.e., direct and indirect) GWPs for ozone-depleting substances (ODSs). Ozone-depleting substances directly absorb infrared radiation and contribute to positive radiative forcing; however, their effect as ozone-depleters also leads to a negative radiative forcing because ozone itself is a potent greenhouse gas. There is considerable uncertainty regarding this indirect effect; therefore, a range of net GWPs is provided for ozone depleting substances.

Table 12. Net 100-year Global Warming Potentials for Select Ozone Depleting Substances*

Gas	Direct	Net _{min}	Net _{max}
CFC-11	4,600	(600)	3,600
CFC-12	10,600	7,300	9,900
CFC-113	6,000	2,200	5,200
HCFC-22	1,700	1,400	1,700
HCFC-123	120	20	100
HCFC-124	620	480	590
HCFC-141b	700	(5)	570
HCFC-142b	2,400	1,900	2,300
CHCl ₃	140	(560)	0
CCl ₄	1,800	(3,900)	660
CH ₃ Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

* Because these compounds have been shown to deplete stratospheric ozone, they are typically referred to as ozone depleting substances (ODSs). However, they are also potent greenhouse gases. Recognizing the harmful effects of these compounds on the ozone layer, in 1987 many governments signed the *Montreal Protocol on Substances that Deplete the Ozone Layer* to limit the production and importation of a number of CFCs and other halogenated compounds. The United States furthered its commitment to phase-out ODSs by signing and ratifying the Copenhagen Amendments to the *Montreal Protocol* in 1992. Under these amendments, the United States committed to ending the production and importation of halons by 1994, and CFCs by 1996. The IPCC Guidelines and the UNFCCC do not include reporting instructions for estimating emissions of ODSs because their use is being phased-out under the *Montreal Protocol*. The effects of these compounds on radiative forcing are not addressed here.

The IPCC recently published its Third Assessment Report (TAR), providing the most current and comprehensive scientific assessment of climate change (IPCC 2001). Within that report, the GWPs of several gases were revised relative to the IPCC's Second Assessment Report (SAR) (IPCC 1996), and new GWPs have been calculated for an expanded set of gases. Since the SAR, the IPCC has applied an improved calculation of CO₂ radiative forcing and an improved CO₂ response function (presented in WMO 1999). The GWPs are drawn from WMO (1999) and the SAR, 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. Because the revised radiative forcing of CO₂ is about 12 percent lower than that in the SAR, the GWPs of the other gases relative to CO₂ tend to be larger, taking into account revisions in lifetimes. However, there were some instances in which other variables, such as the radiative efficiency or the chemical lifetime, were altered that resulted in further increases or decreases in particular GWP values. In addition, the values for radiative forcing and lifetimes have been calculated for a variety of halocarbons, which were not presented in the SAR. The changes are described in the TAR as follows:

New categories of gases include fluorinated organic molecules, many of which are ethers that are proposed as halocarbon substitutes. Some of the GWPs have larger uncertainties than that of others, particularly for those gases where detailed laboratory data on lifetimes are not yet available. The direct GWPs have been calculated relative to CO₂ using an improved calculation of the CO₂ radiative forcing, the SAR response function for a CO₂ pulse, and new values for the radiative forcing and lifetimes for a number of halocarbons.

References

- FCCC (1996) Framework Convention on Climate Change; FCCC/CP/1996/15/Add.1; 29 October 1996; Report of the Conference of the Parties at its second session. Revised Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention, p18. Geneva 1996.
- IPCC (2001) *Climate Change 2001: A Scientific Basis*, Intergovernmental Panel on Climate Change; J.T. Houghton, Y. Ding, D.J. Griggs, M. Noguer, P.J. van der Linden, X. Dai, C.A. Johnson, and K. Maskell, eds.; Cambridge University Press. Cambridge, U.K.
- IPCC (2000) *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*. IPCC National Greenhouse Gas Inventories Programme Technical Support Unit, Kanagawa, Japan. Available online at <<http://www.ipcc-nggip.iges.or.jp/gp/report.htm>>.
- IPCC (1999) *Aviation and the Global Atmosphere*. Intergovernmental Panel on Climate Change; Penner, J.E., et al., eds.; Cambridge University Press. Cambridge, U.K.
- IPCC (1996) *Climate Change 1995: The Science of Climate Change*. Intergovernmental Panel on Climate Change; J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds.; Cambridge University Press. Cambridge, U.K.
- IPCC/UNEP/OECD/IEA (1997) *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*. Paris: Intergovernmental Panel on Climate Change, United Nations Environment Programme, Organization for Economic Co-Operation and Development, International Energy Agency.
- Jacobson, M.Z. (2001) Strong Radiative Heating Due to the Mixing State of Black Carbon in Atmospheric Aerosols. *Nature*. In press.
- UNEP/WMO (2000) *Information Unit on Climate Change*. Framework Convention on Climate Change (Available on the internet at <<http://www.unfccc.de>>.)
- WMO (1999) Scientific Assessment of Ozone Depletion, Global Ozone Research and Monitoring Project-Report No. 44, World Meteorological Organization, Geneva, Switzerland.