

Idaho Greenhouse Gas Inventory and Reference Case Projections 1990-2020

**Center for Climate Strategies
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Disclaimer

The Center for Climate Strategies (CCS) prepared this report for the Idaho Department of Environmental Quality (IDDEQ) through an effort of the Western Regional Air Partnership (WRAP). This report presents a preliminary draft greenhouse gas (GHG) emissions inventory and forecast from 1990 to 2020 for Idaho. This report provides an initial comprehensive understanding of Idaho's current and possible future GHG emissions. The information presented provides the State with a starting point for revising the initial estimates as improvements to data sources and assumptions are identified. Please contact Mr. Robert Wilkosz or Mr. Christopher Ramsdell of the IDDEQ to determine if Idaho has developed any updates to the information presented in this report.

Executive Summary

The Center for Climate Strategies (CCS) prepared this report for the Idaho Department of Environmental Quality (IDDEQ) through an effort of the Western Regional Air Partnership (WRAP). The report contains an inventory and forecast of the State's greenhouse gas (GHG) emissions from 1990 to 2020 to provide an initial comprehensive understanding of Idaho's current and possible future GHG emissions. The information presented provides the State with a starting point for revising the initial estimates as improvements to data sources and assumptions are identified.

Idaho's anthropogenic GHG emissions and anthropogenic 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 emissions estimates (both historical and forecasted), with adjustments by CCS as needed to provide Idaho-specific data and inputs when it was possible to do so. 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 transparent assumptions.

Table ES-1 provides a summary of historical (1990 to 2005) and reference case projection (2010 and 2020) GHG emissions for Idaho. Activities in Idaho accounted for approximately 37 million metric tons (MMt) of *gross*¹ carbon dioxide equivalent (CO₂e) emissions in 2005, an amount equal to about 0.5% of total US gross GHG emissions (based on 2004 US data²). Idaho's gross GHG emissions are rising faster than those of the nation as a whole (gross emissions exclude carbon sinks, such as agricultural soils). Idaho's gross GHG emissions increased 31% from 1990 to 2005, while national emissions rose by only 16% from 1990 to 2004.

Figure ES-1 illustrates the State's emissions per capita and per unit of economic output. Idaho's per capita emission rate is higher than the national average of 25 MtCO₂e/yr. Between 1990 and 2000, per capita emissions in Idaho ranged between 27 MtCO₂e/yr and 28 MtCO₂e/yr, and declined slightly to 26 MtCO₂e/yr between 2000 and 2005. The higher per capita emission rates in Idaho are driven primarily by emissions growth in the agricultural sector (agricultural industry emissions are much higher than the national average). Economic growth exceeded emissions growth in Idaho throughout the 1990-2005 period. From 1990 to 2005, emissions per unit of gross product dropped by 40% nationally, and by 51% in Idaho.³

In 2005, the principle sources of Idaho's GHG emissions are transportation and agriculture, accounting for about 27% and 25% of Idaho's gross GHG emissions, respectively. The next largest contributor to emissions is the residential, commercial, and industrial (RCI) fuel use sector, accounting for 17% of the total State emissions. Emissions associated with in-state production and generation of imported electricity to meet Idaho demand accounts for about 14%

¹ Excluding GHG emissions removed due to forestry and other land uses and excluding GHG emissions associated with exported electricity.

² The national emissions used for these comparisons are based on 2004 emissions, <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

³ Based on gross domestic product by state (millions of current dollars), available from the US Bureau of Economic Analysis (<http://www.bea.gov/regional/gsp/>).

of Idaho's total gross GHG emissions in 2005. Emissions associated with industrial processes, solid and liquid waste management, and fossil fuel production account for about 7% of Idaho's total gross GHG emissions in 2005.

Forestland emissions refer to the net CO₂ flux⁴ from forested lands in Idaho, which account for about 41% of the state's land area.⁵ Idaho's forests are estimated to be net sources of CO₂ emissions contributing about 3.6 MMtCO₂e per year to total GHG emissions in Idaho, accounting for about 10% of total gross GHG emissions in 2005. Agricultural soils, on the other hand, are estimated to be a net GHG emissions sink of 1.2 MMtCO₂e per year.

As illustrated in Figure ES-2 and shown numerically in Table ES-1, under the reference case projections, Idaho's gross GHG emissions continue to grow, and are projected to climb to 44 MMtCO₂e by 2020, reaching 56% above 1990 levels. As shown in Figure ES-3, the transportation sector is projected to be the largest contributor to future emissions growth, followed by emissions associated with the agriculture sector and RCI fossil fuel use in the State.

Some data gaps exist in this analysis, particularly for the reference case projections. Key tasks include review and revision of key emissions drivers that will be major determinants of Idaho's future GHG emissions (such as transportation fuel use, agricultural activities, electricity consumption, fossil fuel production growth rates). Appendices A through H provide the detailed methods, data sources, and assumptions for each GHG sector. Also included are descriptions of significant uncertainties in emission estimates or methods and suggested next steps for refinement of the inventory.

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 Idaho based on 2002 and 2018 data from the WRAP. The results for current levels of BC emissions were a total of 3.2 MMtCO₂e, which is the mid-point of a range of estimated emissions (2.1 – 4.4 MMtCO₂e) in 2002. Based on an assessment of the primary contributors, it is estimated that BC emissions will decrease substantially by 2018 after new engine and fuel standards take effect in the onroad and nonroad diesel engine sectors (decrease of about 2.1 MMtCO₂e). 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 because a global warming potential for BC has not yet been assigned by the Intergovernmental Panel on Climate Change (IPCC). By including BC emission estimates in the inventory, however, additional opportunities for reducing climate impacts can be identified as the scientific knowledge related to BC emissions improves.

⁴ "Flux" refers to both emissions of CO₂ to the atmosphere and removal (sinks) of CO₂ from the atmosphere.

⁵ Total forested acreage is 21.9 million acres. Acreage by forest type available from the USFS at: <http://www.fs.fed.us/ne/global/pubs/books/epa/states/ID.htm>. The total land area in Idaho is 53.5 million acres <http://www.50states.com/idaho.htm>

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

(Million Metric Tons CO ₂ e)	1990	2000	2005	2010	2020	Explanatory Notes for Projections
Energy	16.6	22.2	22.1	23.4	26.8	
Electricity Production	0.0	0.1	0.6	0.6	0.9	
Coal	0.00	0.00	0.00	0.00	0.00	See electric sector assumptions in Appendix A
Natural Gas	0.00	0.09	0.62	0.64	0.92	
Oil	0.00	0.00	0.00	0.00	0.00	
Net Imported Electricity	3.9	4.8	4.7	4.6	5.5	
Electricity Consumption Based	3.9	4.9	5.3	5.2	6.4	
Residential/Commercial/Industrial (RCI) Fuel Use	5.1	6.8	6.1	6.7	7.7	
Coal	0.96	1.29	0.96	1.01	1.00	Based on US DOE regional projections
Natural Gas	2.17	3.47	3.09	3.42	4.05	Based on US DOE regional projections
Oil	1.88	1.95	2.05	2.26	2.58	Based on US DOE regional projections
Wood (CH ₄ and N ₂ O)	0.05	0.06	0.05	0.06	0.06	Based on US DOE regional projections
Transportation	7.3	10.1	10.2	11.0	12.2	
Motor Gasoline	5.25	7.13	6.98	7.25	7.67	Based on US DOE regional projections
Diesel	1.47	2.48	2.79	3.29	4.01	Based on US DOE regional projections
Natural Gas, LPG, other	0.07	0.07	0.07	0.07	0.09	Based on US DOE regional projections
Jet Fuel and Aviation Gasoline	0.46	0.36	0.35	0.37	0.38	Based on US DOE regional projections
Fossil Fuel Industry	0.3	0.4	0.4	0.5	0.6	
Natural Gas Industry	0.32	0.45	0.42	0.46	0.55	Based on US DOE regional projections for natural gas consumption
Oil Industry	0.00	0.00	0.00	0.00	0.00	There is no oil industry in Idaho
Coal Mining (Methane)	0.00	0.00	0.00	0.00	0.00	There are no coal mines in Idaho
Industrial Processes	0.4	0.8	1.1	1.3	1.9	
Cement Manufacture (CO ₂)	0.06	0.06	0.13	0.14	0.16	Based on manufacturing employment projections for Idaho
Lime Manufacture (CO ₂)	0.03	0.03	0.06	0.07	0.08	Ditto
Limestone & Dolomite Use (CO ₂)	0.00	0.00	0.01	0.01	0.01	Ditto
Soda Ash (CO ₂)	0.01	0.01	0.01	0.01	0.01	Based on 2004 and 2009 projections for US production
ODS Substitutes (HFC, PFC, and SF ₆)	0.00	0.35	0.62	0.89	1.52	Based on national projections (US State Dept.)
Semiconductor Manufacturing (HFC, PFC, and SF ₆)	0.08	0.21	0.13	0.09	0.05	Based on national projections (US EPA)
Electric Power T & D (SF ₆)	0.19	0.11	0.09	0.07	0.04	Ditto
Waste Management	1.0	1.2	1.4	1.5	1.8	
Solid Waste Management	0.85	1.09	1.19	1.31	1.59	Projections primarily based on population
Wastewater Management	0.13	0.16	0.17	0.18	0.21	Projections based on population
Agriculture (Ag)	6.8	9.0	9.1	9.9	10.0	
Enteric Fermentation	2.26	2.81	3.19	3.52	3.52	Projections held constant at 2002 levels except for dairy cattle (see Appendix F)
Manure Management	0.70	1.50	1.97	2.33	2.33	Ditto
Ag. Soils and Residue Burning	3.88	4.66	3.97	4.04	4.15	Projections based on trend in historical emissions
Forestry and Land Use	3.6	3.6	3.6	3.6	3.6	Emissions held constant at 2004 levels
Total Gross Emissions	28.4	36.8	37.2	39.6	44.1	
<i>increase relative to 1990</i>		<i>30%</i>	<i>31%</i>	<i>40%</i>	<i>56%</i>	
Agricultural Soils	-1.2	-1.2	-1.2	-1.2	-1.2	Historical and projected emissions held constant at 1997 levels
Net Emissions (including sinks)	27.2	35.6	36.0	38.4	42.9	

^aTotals may not equal exact sum of subtotals shown in this table due to independent rounding.

Figure ES-1. Historical Idaho and US Gross GHG Emissions, Per Capita and Per Unit Gross Product

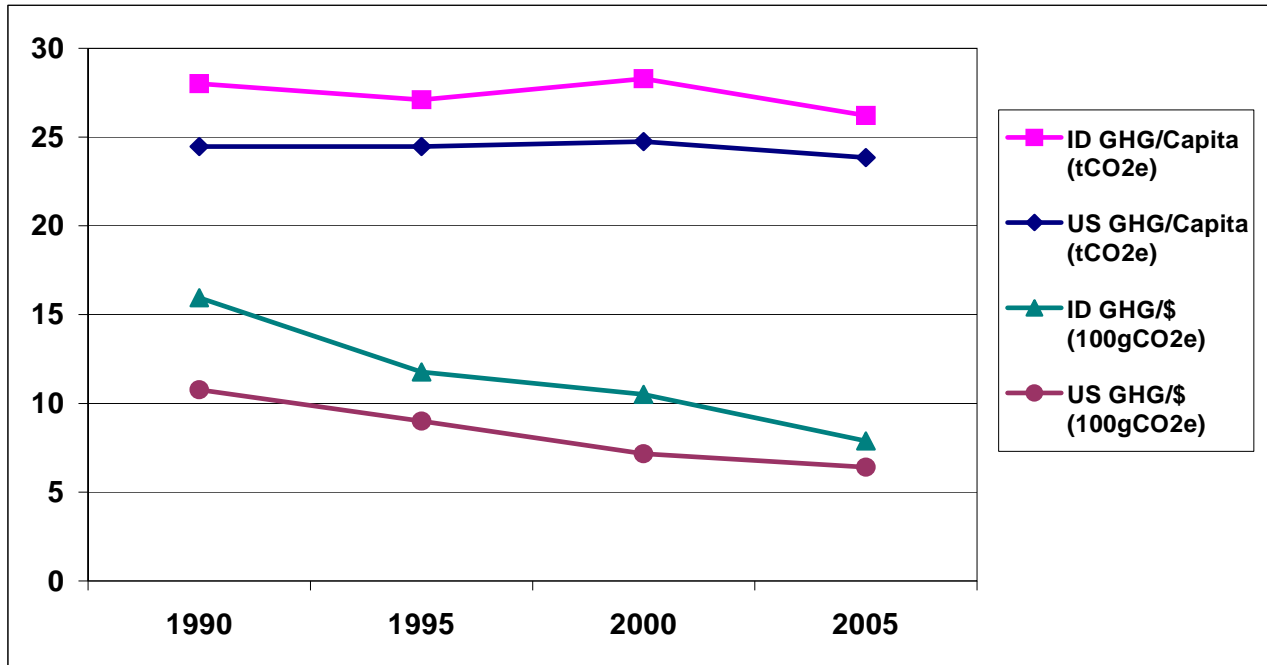
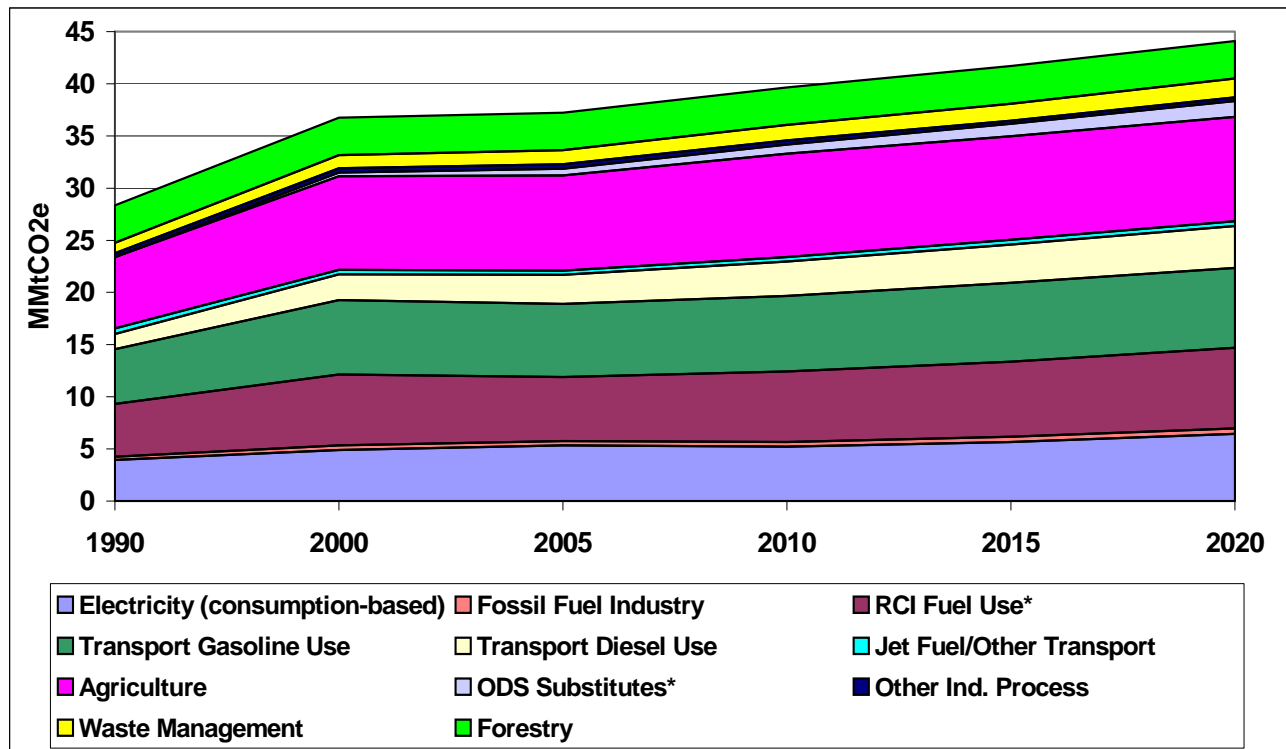
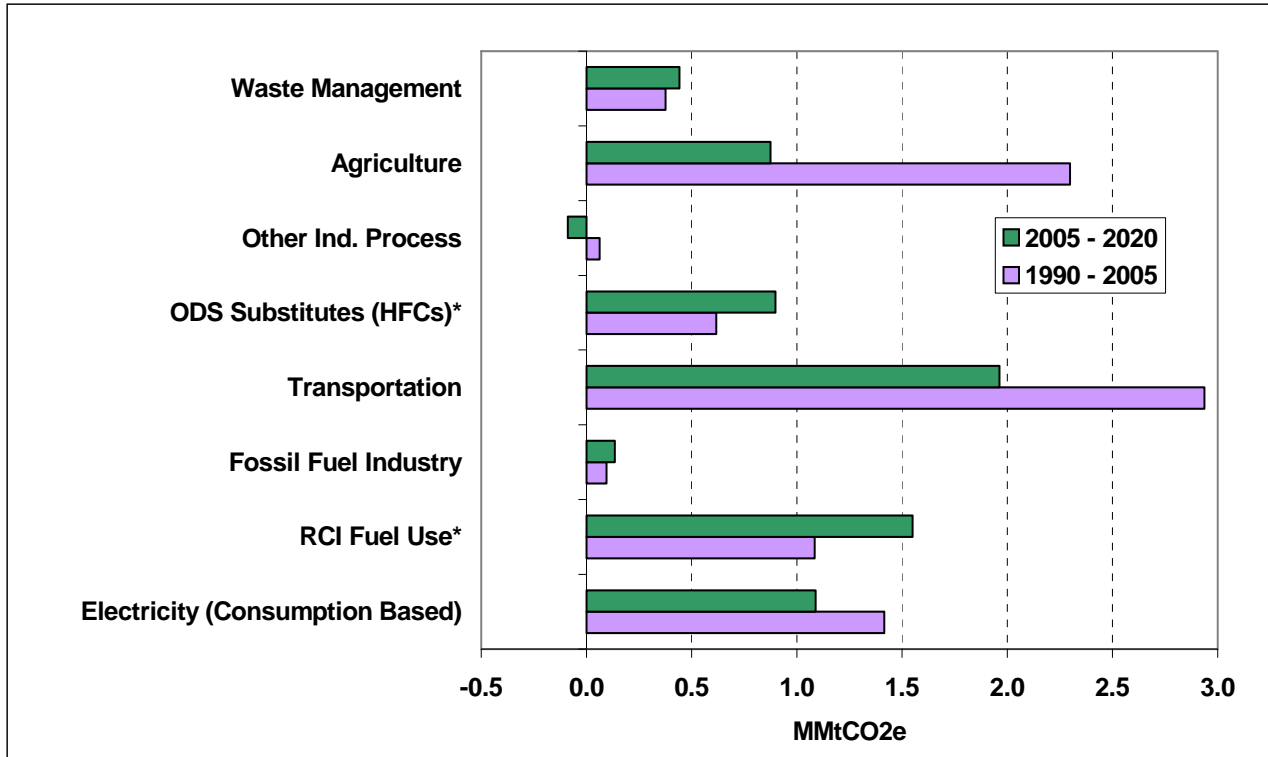


Figure ES-2. Idaho Gross GHG Emissions by Sector, 1990-2020: Historical and Projected



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

**Figure ES-3. Sector Contributions to Gross Emissions Growth in Idaho, 1990-2020:
 Reference Case Projections (MMtCO₂e Basis)**



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

Table of Contents

Acronyms and Key Terms	vii
Acknowledgements.....	x
Summary of Preliminary Findings.....	1
Introduction.....	1
Idaho Greenhouse Gas Emissions: Sources and Trends	2
Historical Emissions	4
Overview.....	4
A Closer Look at the Two Major Sources: Transportation and Agriculture	6
Reference Case Projections.....	7
Key Uncertainties and Next Steps	7
Approach.....	9
General Methodology	9
General Principles and Guidelines.....	10
Appendix A. Electricity Use and Supply.....	A-1
Appendix B. Residential, Commercial, and Industrial (RCI) 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 Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2000.....	J-1

Acronyms and Key Terms

AEO – Annual Energy Outlook, EIA
Ag – Agriculture
bbls – Barrels
BC – Black Carbon*
Bcf – Billion cubic feet
BLM – United States Bureau of Land Management
BOC – Bureau of Census
BOD – Biochemical Oxygen Demand
BTU – British thermal unit
C – Carbon*
CaCO₃ – Calcium Carbonate
CBM – Coal Bed Methane
CCS – Center for Climate Strategies
CFCs – Chlorofluorocarbons*
CH₄ – Methane*
CO – Carbon Monoxide*
CO₂ – Carbon Dioxide*
CO_{2e} – Carbon Dioxide equivalent*
CRP – Federal Conservation Reserve Program
EC – Elemental Carbon*
eGRID – US EPA’s Emissions & Generation Resource Integrated Database
EGU – Electricity Generating Unit
EIA – US DOE Energy Information Administration
EIIP – Emissions Inventory Improvement Program
Eq. – Equivalent
FAA – Federal Aviation Administration
FIA – Forest Inventory and Analysis
Gg – Gigagram
GHG – Greenhouse Gases*
GWh – Gigawatt-hour
GWP – Global Warming Potential*

HFCs – Hydrofluorocarbons*

IDDEQ – Idaho Department of Environmental Quality

IPCC – Intergovernmental Panel on Climate Change*

kWh – kilowatt-hour

LF – Landfills

LFGTE – Landfill Gas Collection System and Landfill-Gas-to-Energy

LMOP – Landfill Methane Outreach Program

LNG – Liquefied Natural Gas

LPG – Liquefied Petroleum Gas

Mt – Metric ton (equivalent to 1.102 short tons)

MMt – Million Metric tons

MSW – Municipal Solid Waste

MW – Megawatt

MWh – Megawatt-hour

N – Nitrogen*

N₂O – Nitrous Oxide*

NO₂ – Nitrogen Dioxide*

NO_x – Nitrogen Oxides*

NASS – National Agricultural Statistics Service

NF – National Forest

NMVOCs – Non-methane Volatile Organic Compounds*

O₃ – Ozone*

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

SAR – Second Assessment Report*

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

Tg – Teragram

TWh – Terawatt-hours

UNFCCC – United Nations Framework Convention on Climate Change

US EPA – United States Environmental Protection Agency

US 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

WECC – Western Electricity Coordinating Council

W/m² – Watts per Square Meter

WMO – World Meteorological Organization*

WRAP – Western Regional Air Partnership

WW – Wastewater

* – See Appendix J for more information.

Acknowledgements

We appreciate all of the time and assistance provided by numerous contacts throughout Idaho, as well as in neighboring States, and at federal agencies. Thanks go to in particular the many staff at several Idaho State Agencies for their inputs, and in particular to Robert Wilkosz, Martin Bauer, and Christopher Ramsdell of the Idaho Department of Environmental Quality (IDDEQ) who provided key guidance for this analytical effort.

The authors would also like to express their appreciation to Katie Bickel, Michael Lazarus, Lewison Lem, Katie Pasko, and David Von Hippel of the Center for Climate Strategies (CCS) who provided valuable review comments during development of this report. Thanks also to Michael Gillenwater for directing preparation of Appendix J.

Summary of Preliminary Findings

Introduction

The Center for Climate Strategies (CCS) prepared this report for the Idaho Department of Environmental Quality (IDDEQ) through an effort of the Western Regional Air Partnership (WRAP). This report presents initial estimates of base year and projected anthropogenic greenhouse gas (GHG) emissions and anthropogenic sinks (carbon storage) 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 Idaho. The information presented provides the State with a starting point for revising the initial estimates as improvements to data sources and assumptions are identified.

Historical GHG emission estimates (1990 through 2005)⁶ were developed using a set of generally accepted principles and guidelines for State GHG emissions inventories, as described in the “Approach” section below, relying to the extent possible on Idaho-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 gases included in the US 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.⁷ 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 emissions estimates for the electricity sector reflect the *GHG emissions associated with the electricity sources used to meet Idaho’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*. This report covers both methods of accounting for emissions, but for consistency, all total results are reported as *consumption-based*.

⁶ The last year of available historical data varies by sector; ranging from 2000 to 2005.

⁷ These gases and the concepts of radiative forcing and GWP are described in Appendix J.

Idaho Greenhouse Gas Emissions: Sources and Trends

Table 1 provides a summary of GHG emissions estimated for Idaho by sector for the years 1990, 2000, 2005, 2010, and 2020. Details on the methods and data sources used to construct these estimates are provided in the appendices to this report. 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 clearly for each.

This next section of the report provides a summary of the historical emissions (1990 through 2005) followed by a summary of the reference-case projection-year emissions (2006 through 2020) and key uncertainties. We also provide 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 black carbon (BC) estimates for Idaho. CCS estimated that BC emissions in 2002 ranged from 2.1 – 4.4 million metric tons (MMt) of carbon dioxide equivalent (CO₂e) with a mid-point of 3.2 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 CO₂e. Emissions in key contributing sectors are expected to drop by about 2.1 MMtCO₂e/yr by 2018 as a result of new engine and fuel standards affecting onroad and nonroad diesel engines. Appendix I contains a detailed breakdown of 2002 emissions contribution by source sector. 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.

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

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

(Million Metric Tons CO ₂ e)	1990	2000	2005	2010	2020	Explanatory Notes for Projections
Energy	16.6	22.2	22.1	23.4	26.8	
Electricity Production	0.0	0.1	0.6	0.6	0.9	
Coal	0.00	0.00	0.00	0.00	0.00	See electric sector assumptions in Appendix A
Natural Gas	0.00	0.09	0.62	0.64	0.92	
Oil	0.00	0.00	0.00	0.00	0.00	
Net Imported Electricity	3.9	4.8	4.7	4.6	5.5	
Electricity Consumption Based	3.9	4.9	5.3	5.2	6.4	
Residential/Commercial/Industrial (RCI) Fuel Use	5.1	6.8	6.1	6.7	7.7	
Coal	0.96	1.29	0.96	1.01	1.00	Based on US DOE regional projections
Natural Gas	2.17	3.47	3.09	3.42	4.05	Based on US DOE regional projections
Oil	1.88	1.95	2.05	2.26	2.58	Based on US DOE regional projections
Wood (CH ₄ and N ₂ O)	0.05	0.06	0.05	0.06	0.06	Based on US DOE regional projections
Transportation	7.3	10.1	10.2	11.0	12.2	
Motor Gasoline	5.25	7.13	6.98	7.25	7.67	Based on US DOE regional projections
Diesel	1.47	2.48	2.79	3.29	4.01	Based on US DOE regional projections
Natural Gas, LPG, other	0.07	0.07	0.07	0.07	0.09	Based on US DOE regional projections
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Fossil Fuel Industry	0.3	0.4	0.4	0.5	0.6	
Natural Gas Industry	0.32	0.45	0.42	0.46	0.55	Based on US DOE regional projections for natural gas consumption
Oil Industry	0.00	0.00	0.00	0.00	0.00	There is no oil industry in Idaho
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Cement Manufacture (CO ₂)	0.06	0.06	0.13	0.14	0.16	Based on manufacturing employment projections for Idaho
Lime Manufacture (CO ₂)	0.03	0.03	0.06	0.07	0.08	Ditto
Limestone & Dolomite Use (CO ₂)	0.00	0.00	0.01	0.01	0.01	Ditto
Soda Ash (CO ₂)	0.01	0.01	0.01	0.01	0.01	Based on 2004 and 2009 projections for US production
ODS Substitutes (HFC, PFC, and SF ₆)	0.00	0.35	0.62	0.89	1.52	Based on national projections (US State Dept.)
Semiconductor Manufacturing (HFC, PFC, and SF ₆)	0.08	0.21	0.13	0.09	0.05	Based on national projections (US EPA)
Electric Power T & D (SF ₆)	0.19	0.11	0.09	0.07	0.04	Ditto
Waste Management	1.0	1.2	1.4	1.5	1.8	
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Agriculture (Ag)	6.8	9.0	9.1	9.9	10.0	
Enteric Fermentation	2.26	2.81	3.19	3.52	3.52	Projections held constant at 2002 levels except for dairy cattle (see Appendix F)
Manure Management	0.70	1.50	1.97	2.33	2.33	Ditto
Ag. Soils and Residue Burning	3.88	4.66	3.97	4.04	4.15	Projections based on trend in historical emissions
Forestry and Land Use	3.6	3.6	3.6	3.6	3.6	Emissions held constant at 2004 levels
Total Gross Emissions	28.4	36.8	37.2	39.6	44.1	
<i>increase relative to 1990</i>		<i>30%</i>	<i>31%</i>	<i>40%</i>	<i>56%</i>	
Agricultural Soils	-1.2	-1.2	-1.2	-1.2	-1.2	Historical and projected emissions held constant at 1997 levels
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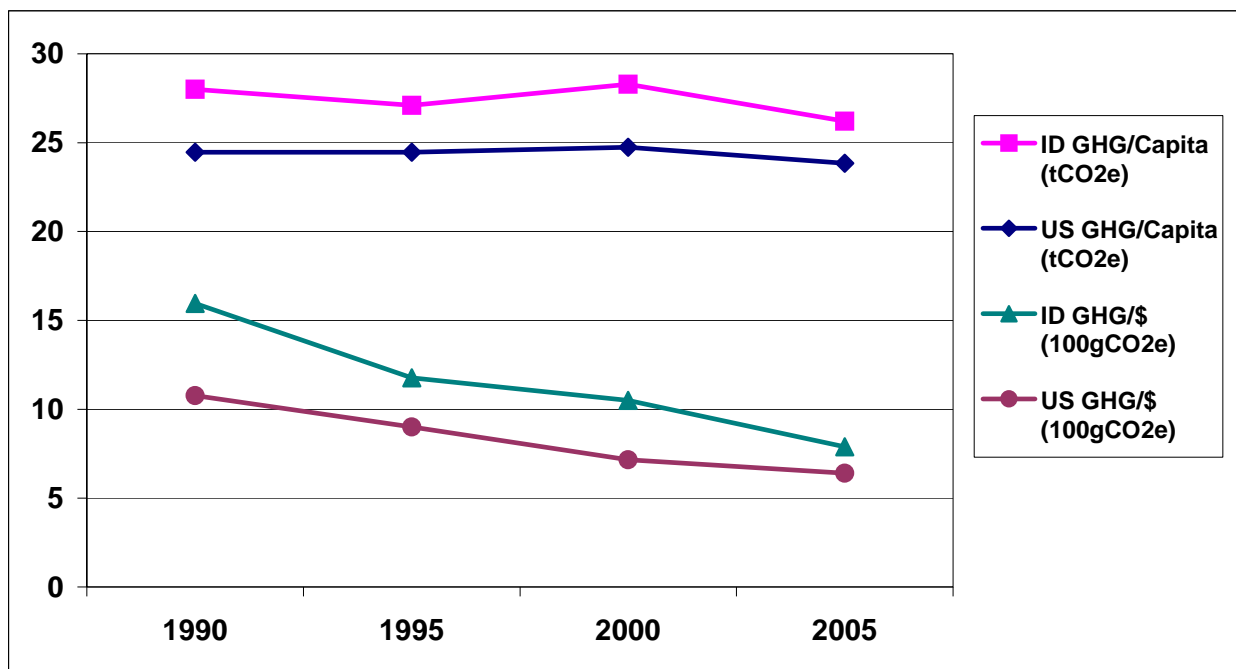
Historical Emissions

Overview

Preliminary analyses suggest that in 2005, activities in Idaho accounted for approximately 37 million metric tons (MMt) of CO₂e emissions, an amount equal to about 0.5% of total US GHG emissions (based on 2004 US emissions).⁸ Idaho's gross GHG emissions are rising faster than those of the nation as a whole (gross emissions exclude carbon sinks, such as forests). Idaho's gross GHG emissions increased 31% from 1990 to 2005, while national emissions rose by only 16% from 1990 to 2004.

Figure 1 illustrates the State's emissions per capita and per unit of economic output. Idaho's per capita emission rate is higher than the national average of 25 MtCO₂e/yr. Between 1990 and 2000, per capita emissions in Idaho ranged between 27 MtCO₂e/yr and 28 MtCO₂e/yr, and declined slightly to 26 MtCO₂e/yr between 2000 and 2005. The higher per capita emission rates in Idaho are driven primarily by emissions growth in the agricultural sector (agricultural industry emissions are much higher than the national average). Economic growth exceeded emissions growth in Idaho throughout the 1990-2005 period. From 1990 to 2005, emissions per unit of gross product dropped by 40% nationally, and by 51% in Idaho.⁹

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

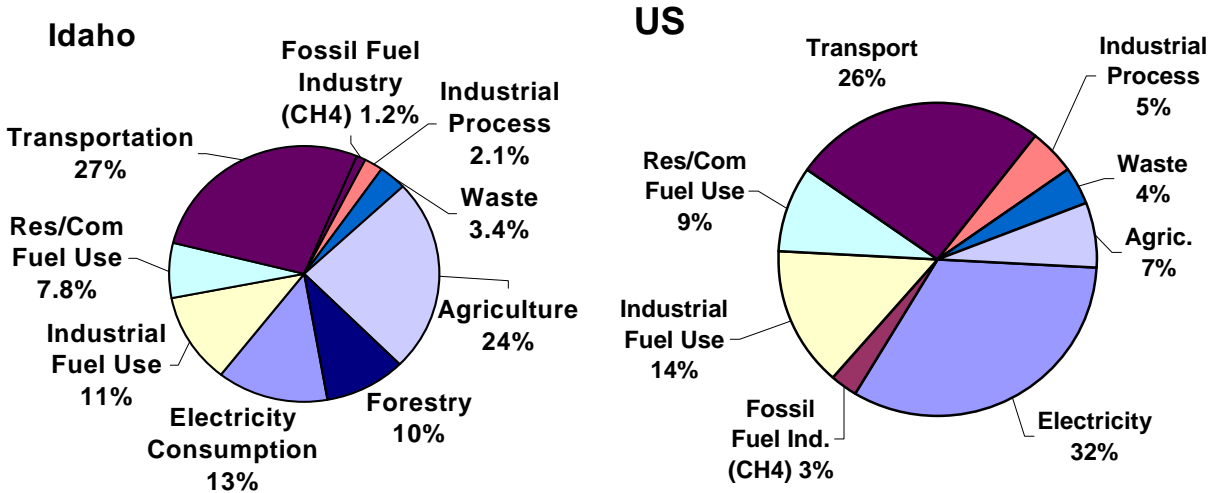


⁸ United States emissions estimates are drawn from US EPA 2006, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2004*.

⁹ Based on gross domestic product by state (millions of current dollars), available from the US Bureau of Economic Analysis (<http://www.bea.gov/regional/gsp/>). The national emissions used for these comparisons are based on 2004 emissions, <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

Transportation and agriculture are the State’s principle GHG emissions sources. Together, these two sectors accounted for 51% of Idaho’s gross GHG emissions in 2000, as shown in Figure 2. The use of fossil fuels — natural gas, oil products, and coal — in the residential, commercial, and industrial (RCI) sectors constituted another 19% of total State emissions. The combustion of fossil fuels for electricity generation (including emissions associated with the generation of electricity imported from other States) constituted only 13% of total State emissions which is a little less than the nation as a whole.

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



NOTE: at a national level, forests act as a net sink of CO₂; therefore, they do not show up in the above graph of gross U.S. emissions sources.

Industrial process emissions comprised almost 2% of State GHG emissions in 2000. Although industrial process emissions are rising rapidly due to the increasing use of HFC as substitutes for ozone-depleting chlorofluorocarbons (CFCs), their overall contribution is estimated to be only 3.4% of Idaho’s gross GHG emissions in 2020 due to significant growth in other sectors.¹⁰ Other industrial process emissions result from CO₂ released during soda ash, limestone, and dolomite use. Landfills and wastewater management facilities, and the fossil fuel industry produced CH₄ and N₂O emissions that together accounted for over 5% of the State’s emissions in 2000.

Forestland emissions refer to the net CO₂ flux¹¹ from forested lands in Idaho, which account for about 41% of the state’s land area.¹² The dominant forest types in Idaho are Douglas fir forests which make up about 34% of forested lands and Fir-Spruce forests which make up another 24%.

¹⁰ CFCs are also potent GHGs; they are not, however, included in GHG estimates because of concerns related to implementation of the Montreal Protocol (See Appendix I for additional information). HFCs are used as refrigerants in the RCI and transport sectors as well as in the industrial sector; they are included here, however, within the industrial processes emissions.

¹¹ “Flux” refers to both emissions of CO₂ to the atmosphere and removal (sinks) of CO₂ from the atmosphere.

¹² Total forested acreage is 21.9 million acres. Acreage by forest type available from the USFS at: <http://www.fs.fed.us/ne/global/pubs/books/epa/states/ID.htm>. The total land area in Idaho is 53.5 million acres (<http://www.50states.com/idaho.htm>)

Other important forest types are Ponderosa pine, Lodgepole pine, and Hemlock-Sitka spruce forests. Based on U.S. Forest Service (USFS) data, Idaho's forests are estimated to be a net source of CO₂ emissions contributing about 3.6 MMtCO₂e per year to total GHG emissions in Idaho, which accounts for about 10% of Idaho's total gross GHG emissions in 2000. Due to uncertainties in projecting the future levels of net CO₂ emissions from the State's forests, the projected sinks were held constant at current levels. Agricultural soils, on the other hand, are estimated to be a net GHG emissions sink of 1.2 MMtCO₂e per year.

A Closer Look at the Two Major Sources: Transportation and Agriculture

As shown in Figure 2, the transportation sector accounted for about 27% of Idaho's gross GHG emissions in 2000 (about 10 MMtCO₂e), which was slightly higher than the national average share of emissions from transportation fuel consumption (26%). The GHG emissions associated with Idaho's transportation sector increased by 2.8 MMtCO₂e between 1990 and 2000, accounting for about 33% of the State's net growth in gross GHG emissions in this time period.

From 1990 through 2002, GHG emissions from transportation fuel use have risen steadily at an average rate of about 2.6% annually. In 2002, onroad gasoline vehicles accounted for about 70% of transportation GHG emissions. Onroad diesel vehicles accounted for another 24% of emissions, and air travel for roughly 4%. Rail, marine gasoline, and other sources (natural gas- and liquefied petroleum gas- (LPG-) fueled-vehicles used in transport applications) accounted for the remaining 2% of transportation emissions. As a result of Idaho's population and economic growth and an increase in total vehicle miles traveled (VMT) during the 1990s, onroad gasoline use grew 32% between 1990 and 2002. Meanwhile, onroad diesel use rose 72% during that period, suggesting an even more rapid growth in freight movement within or across the State. Aviation fuel use declined by about 26% from 1990-2002.

Emissions associated with the agriculture sector include CH₄ and N₂O emissions from enteric fermentation, manure management, and agricultural soils. Methane emissions from enteric fermentation are the result of normal digestive processes in ruminant and non-ruminant livestock. 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 agricultural soils category accounts for several sources of N₂O emissions, including decomposition of crop residues, synthetic and organic fertilizer application, manure and sewage sludge application to soils, and nitrogen fixation. Both direct and indirect emissions of N₂O occur from the application of manure, fertilizer, and sewage sludge to agricultural soils (see Appendix F for more details).

The agricultural sector accounted for about 24% of Idaho's gross GHG emissions in 2000 (about 9 MMtCO₂e), which was significantly higher than the national average share of emissions from the agricultural sector (7%). Animal husbandry operations are the primary contributor to emissions in the agricultural sector. From 1990 through 2002, emissions associated with enteric fermentation and manure management have increased at an average annual rate of about 2.2% and 7.6%, respectively. The high growth rates associated with enteric fermentation and manure management are driven by significant growth in primarily the dairy cattle population, and to a lesser extent by the beef cattle and swine populations in Idaho. Emissions associated with the management of agricultural soils contributed significantly less to total gross GHG emissions in

the agricultural sector, with emissions increasing at about 0.2% annually from 1990 through 2002.

Reference Case Projections

Relying on a variety of sources for projections, 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, Idaho gross GHG emissions continue to grow steadily, climbing to about 40.5 MMtCO₂e by 2020, 64% above 1990 levels. The transportation sector is projected to be the largest contributor to future emissions growth, followed by emissions associated with the agricultural sector, the consumption of fossil fuels to meet electricity demand, and RCI fossil fuel use, as shown in Figure 4.

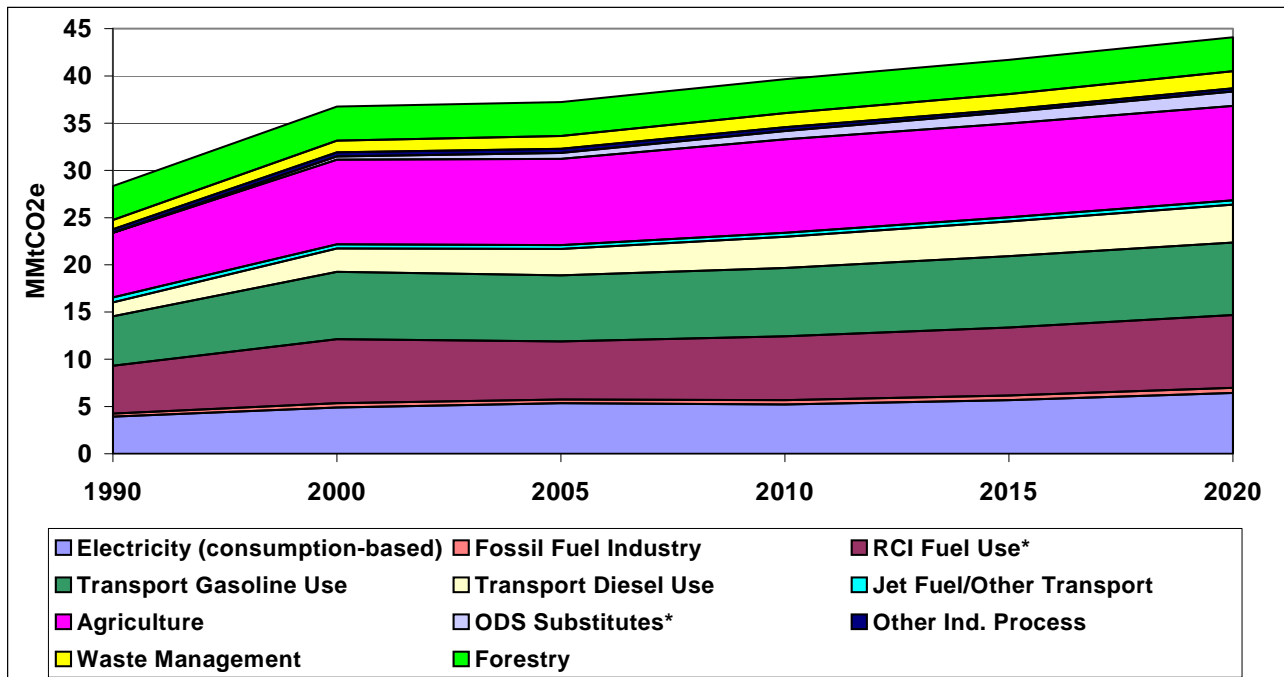
Key Uncertainties and Next Steps

Some data gaps exist in this inventory, and particularly in the reference case projections. Key tasks for future refinement of this inventory and forecast include review and revision of key drivers, such as the transportation, agriculture, electricity demand, and RCI fuel use growth rates that will be major determinants of Idaho's future GHG emissions (See Table 2 and Figure 4). These growth rates are driven by uncertain economic, demographic and land use trends (including growth patterns and transportation system impacts), all of which deserve closer review and discussion.

As examples, the assumptions on VMT and air travel growth have large impacts on projected GHG emissions growth in the State. Also, uncertainty remains on estimates for future livestock populations in the State. Finally, historic and projected GHG sinks from forestry, which can greatly affect the net GHG emissions attributed to Idaho, should be revised as new estimates are produced by the USFS to support the national inventory.

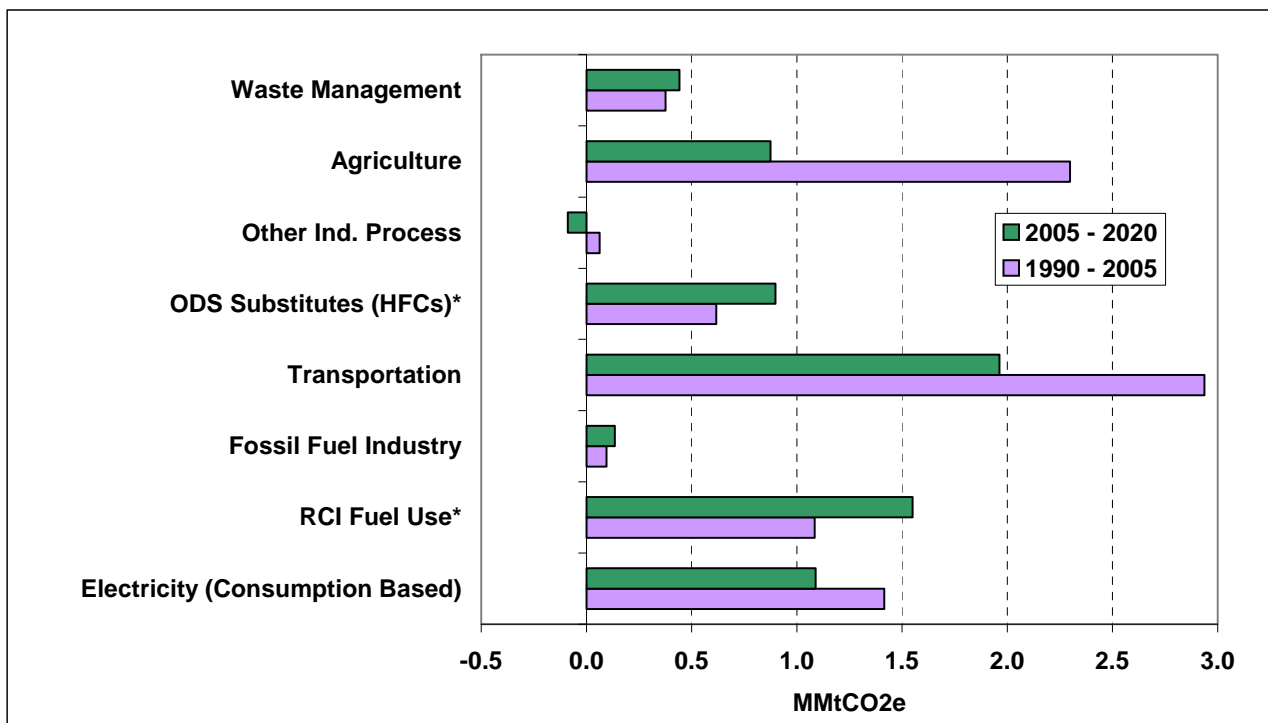
Emissions of aerosols, particularly BC from fossil fuel combustion, could have significant impacts in terms of radiative forcing (i.e., climate impacts). Methodologies for conversion of BC mass estimates and projections to global warming potential involve significant uncertainty at present, but CCS has developed and used an approach for estimating BC emissions based on methods used in other States. Current estimates suggest a fairly significant CO₂e contribution from BC emissions, as compared to the CO₂e contributed from the gases (about 10% BC contribution relative to the CO₂e from the gases in 2000). However, emissions in key contributing sectors (onroad and nonroad diesel engines) are expected to decline by 2020; see Appendix I).

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



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

Figure 4. Sector Contributions to Gross Emissions Growth in Idaho, 1990-2020: Historic and Reference Case Projections (MMtCO₂e Basis)



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

Table 2. Key Annual Growth Rates for Idaho, Historical and Projected

	1990-2005	2005-2020	Sources
Population*	2.3%	1.7%	Idaho Power 2006 <i>Integrated Resource Plan - Appendix C - Economic Forecast</i>
Employment*			
Goods	2.0%	1.3%	Idaho Power 2006 <i>Integrated Resource Plan - Appendix C - Economic Forecast</i>
Services	3.2%	2.3%	
Electricity Sales	1.4%	1.8% - 2.1%	US DOE Energy Information Administration (EIA) data for 1990-2004 (1.4% growth is mix of residential, commercial, and industrial electricity sales). A growth rate of 2.1% was estimated for 2005-2010 and a growth rate of 1.8% was estimated for 2011-2020 based on electricity sales forecasts developed for the energy supply sector (see Appendix A).
Vehicle Miles Traveled	2.8%	1.4%	Idaho Transportation Department (ITD)

* For the RCI fuel consumption sectors, population and employment projections for Idaho were used together with US DOE EIA’s Annual Energy Outlook 2006 (AEO2006) projections of changes in fuel use for the EIA’s Mountain region on a per capita basis for the residential sector, and on a per employee basis for the commercial and industrial sectors. For instance, growth in Idaho’s residential natural gas use is calculated as the Idaho population growth times the change in per capita natural gas use for the Mountain region.

Approach

The principle goal of compiling the inventories and reference case projections presented in this document is to provide the State of Idaho with a general understanding of Idaho’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 Idaho.

General Methodology

We prepared this analysis in close consultation with Idaho agencies, in particular, with the IDDEQ 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 existing forecasts are lacking, we use straightforward spreadsheet analysis and constant growth-rate 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 inventory¹³ and its guidelines for States.¹⁴ These inventory guidelines were developed based on the guidelines from the IPCC, the international organization responsible for developing coordinated methods for national GHG inventories.¹⁵ The inventory methods provide flexibility to account for local conditions. The key

¹³ 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>.

¹⁴ <http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html>.

¹⁵ <http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm>

sources of activity and projection data used are shown in Table 3. Table 3 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 projections, 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 Idaho. It covers all six GHGs covered by US and other national inventories: CO₂, CH₄, N₂O, SF₆, HFCs, PFCs, and BC. 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.
- **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 Idaho. For example, we reported emissions associated with the electricity consumed in Idaho. 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.

Table 3. Key Sources for Idaho 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 VIII 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 RCI fuel combustion, transportation, industrial processes, 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 provides energy use data in each State, annually to 2003 for all fuels and 2004 for oil and natural gas.	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 EIA website for years after 2003. Emission factors from US EPA SGIT are used to calculate energy-related emissions.
EIA AEO2006	EIA AEO2006 projects energy supply and demand for the US from 2003 to 2030. Energy consumption is estimated on a regional basis. Idaho is included in the Mountain Census region (AZ, CO, ID, MT, NM, NV, UT, and WY).	EIA AEO2006 is used to project changes in per capita (residential), per employee (commercial/industrial).
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.
US Forest Service	Data on forest carbon stocks for multiple years.	Data are used to calculate CO ₂ flux over time (terrestrial CO ₂ sequestration in forested areas).
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.

For electricity, we estimate, in addition to the emissions due to fuels combusted at electricity plants in the State, the emissions related to electricity *consumed* in Idaho. This entails accounting for the electricity sources used by Idaho utilities to meet consumer demands. As we refine this analysis, we may also attempt to estimate other sectoral emissions on a consumption basis, such as accounting for emissions from transportation fuel used in Idaho, but purchased out-of-state. In

some cases this can require venturing into the relatively complex terrain of life-cycle analysis. In general, we recommend 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) Fuel Combustion;
- Appendix C. Transportation Energy Use;
- Appendix D. Industrial Processes;
- Appendix E. Fossil Fuel Industries;
- Appendix F. Agriculture;
- Appendix G. Waste Management; and
- Appendix H. Forestry.

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

Appendix A. Electricity Use and Supply

Historically, much of Idaho's electricity has been imported into the State from power plants in neighboring states. The relatively low amount of in-state generation is dominated by hydro-electric plants and a few natural gas plants. This situation – high levels of imports combined with a mix of renewable and natural gas generation in-state – is projected to continue throughout the projection period of this analysis. As noted earlier, one of the key questions for the State to consider is how to treat GHG emissions that result from generation of electricity that is produced in other states to meet Idaho's electricity needs. In other words, should the State consider the GHG emissions associated with the State's electricity consumption or its electricity production, or some combination of the two? Since this question still needs to be resolved, this section examines electricity-related emissions from both a production and consumption basis.

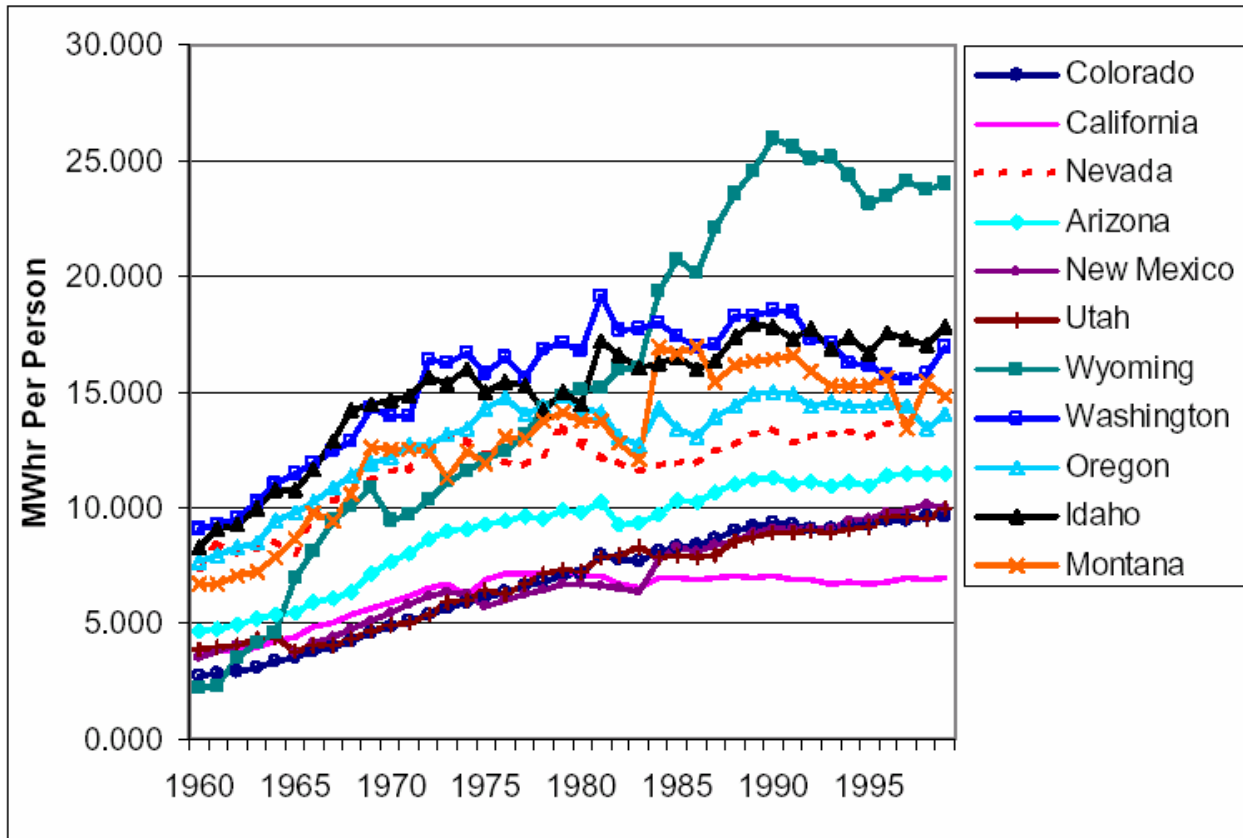
This appendix assesses Idaho's electricity sector in terms of net consumption and production emissions, and describes the assumptions used to develop the reference case projections. It then describes inter-state electricity trade and potential approaches for allocating GHG emissions for the purpose of determining the State's inventory and reference case forecasts. Finally, key assumptions and results are summarized.

Electricity Consumption

At about 15,700 kWh/capita (2004 data), Idaho has relatively high electricity consumption per capita. By way of comparison, the per capita consumption for the U.S. was about 12,000 kWh per year.¹⁶ Figure A1 shows Idaho's rank compared to other western states from 1960-1999; ranking along with Wyoming and Washington in the top three States in terms of per capita electricity consumption. Many components influence a state's per capita electricity consumption including the impact of weather on demand for heating and cooling, the price of electricity, the size and type of industries in the State, the prevalence of electric heating, and the type and efficiency of equipment in the residential, commercial and industrial sectors.

¹⁶ Census bureau for U.S. population, Energy Information Administration for electricity sales.

Figure A1. Electricity Consumption per capita in Western States, 1960-1999



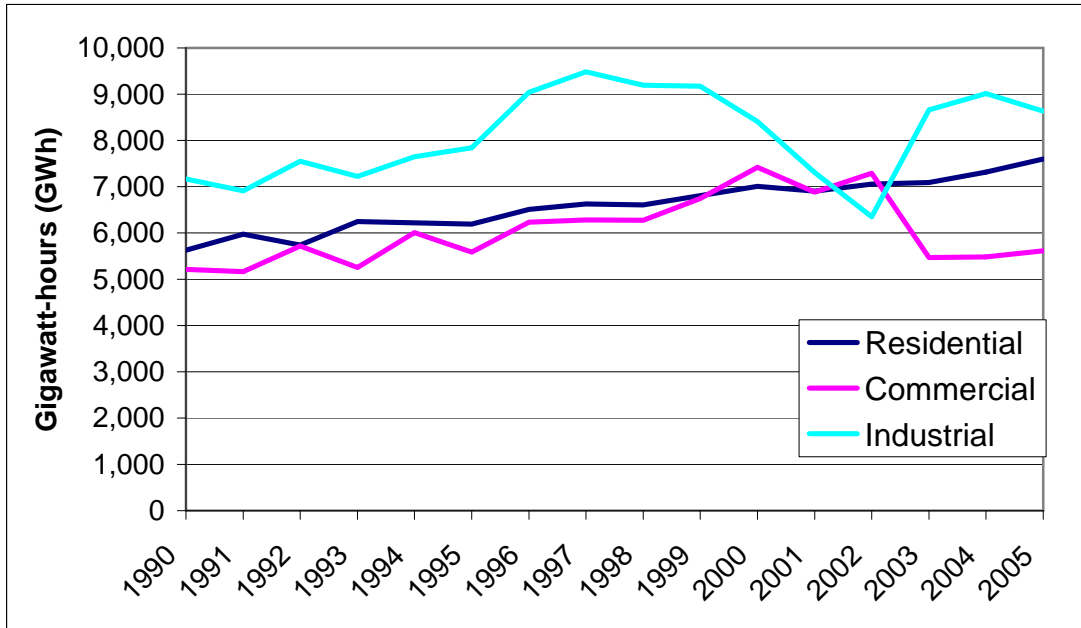
Source: Northwest Power Council, 5th Power Plan, Appendix A

As shown in Figure A2, electricity sales in Idaho have shown minor increases from 1990 through 2005. Overall, total electricity consumption increased at an average annual rate of 1.3% from 1990 to 2005, lower than the population growth rate of 2.3% per year.¹⁷ During this period, electricity sales in the residential sector grew by an average of 1.8% per year. Both the commercial sector and the industrial sector showed significant increases and decreases since 2000.¹⁸ The average annual growth in electricity sales between 1990 and 2005 was 0.3% for the commercial sector and 1.5% for the industrial sector.

¹⁷ Population from Idaho Power, 2006 Integrated Resource Plan, Appendix C – Economic Forecast, "Forecast of Population, Households, and Persons per Household", Compiled and prepared by John Church, Idaho Economics, P.O. Box 45694, Boise, ID 83711-5694, (208) 323-0732, e-mail: ideconomics@earthlink.net.

¹⁸ CCS has attempted to determine if the changes in electricity sales by sector are related to data reporting by sector, rather than actual changes in sales. The data source for this information is the Energy Information Administration (EIA) - State Energy Data and Electric Power Annual. EIA staff responded that the data are provided by utilities based on filling out consistent data forms. However EIA were unable to verify the data beyond what utilities provided.

Figure A2. Electricity Consumption by Sector in Idaho, 1990-2005¹⁹



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 a sales weighted average of electricity sales projected by the three largest utilities in Idaho, Idaho Power, PacifiCorp and Avista.²⁰ Since these three utilities account for over 87% of Idaho’s retail electricity sales, the projections from their load forecasts are assumed to be representative of the whole state and have been applied to total electricity sales. Table A1 reports historic and projected annual average growth rates.

¹⁹ 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 A2, the sales from the “other” category are included with the commercial sector. The decision to include with commercial rather than the other sectors is based on comparing the trends of electricity sales from 2000-2002 with 2003 sales.

²⁰ Idaho Power. *2006 Integrated Resource Plan*. PacifiCorp’s projections for Idaho were found in a powerpoint presentation from one of PacifiCorp’s Public Input Meeting for the 2006 Integrated Resource Plan (April 20, 2006). <http://www.utah-power.com/File/File64180.pdf>. Accessed on November 14, 2006. Avista. *2005 Integrated Resource Plan*.

Table A1. Electricity Growth Rates, historic and projected

	Historic		Projections	
	1990-2000	2000-2005	2005-2010	2010-2020
Residential	2.2%	1.6%	2.0%	1.7%
Commercial	3.6%	-5.4%	2.7%	2.2%
Industrial	1.6%	0.5%	1.8%	1.5%
Total	2.4%	-0.9%	2.1%	1.8%

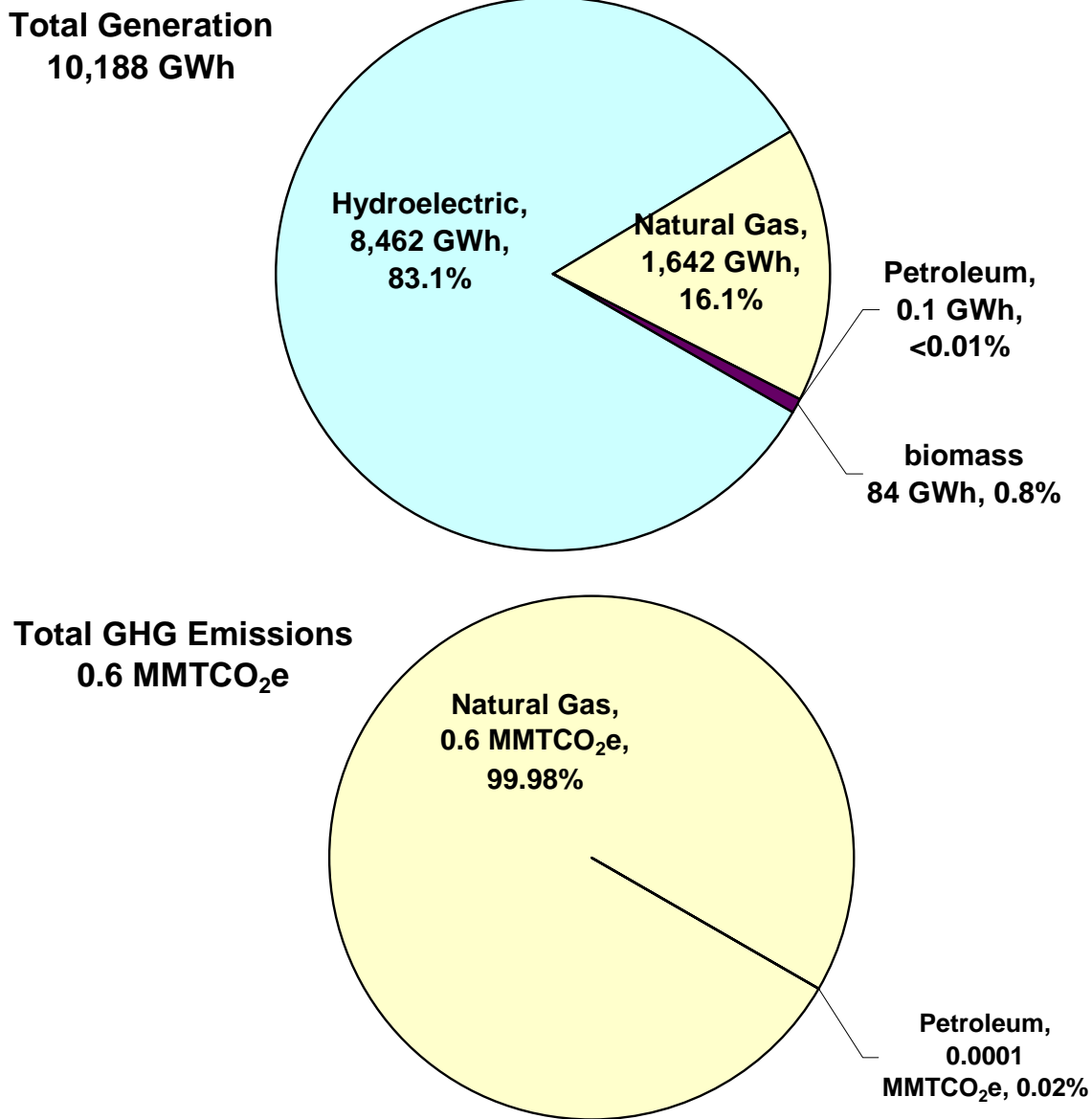
Source: Historic from EIA data, projections are CCS calculations for the sales weighted growth based on Idaho Power 2006 Integrated Resource Plan; PacifiCorp 2006 Load Forecast; and Avista 2005 Integrated Resource Plan.

Electricity Generation – Idaho’s Power Plants

The following section provides information on GHG emissions and other activity associated with power plants *located in Idaho*. Since Idaho is part of the interconnected Western Electricity Coordinating Council (WECC) region – electricity generated in Idaho can be exported to serve needs in other states and electricity used in Idaho can be generated in plants outside the state. For this analysis, we estimate emissions on both a *production-basis* (emissions associated with electricity produced in Idaho, regardless of where it is consumed) and a net *consumption-basis* (emissions associated with electricity consumed in Idaho). The following section describes production-based emissions while the subsequent section, *Electricity trade and the allocation of GHG emissions*, reports consumption-based emissions.

As displayed in Figure A3, hydro-electricity generation figures prominently in electricity generation in Idaho. However, since hydro-electricity does not produce GHG emissions, the State’s GHG emissions are due almost entirely to the natural gas generation. At 0.6 MMTCO_{2e} of emissions in 2004, Idaho has the second lowest level for total GHG emissions of any US state. Idaho’s GHG emissions result mostly from the Rathdrum Power Plant (a 270 MW combined cycle plant) and the Rathdrum Combustion Turbine plants operated by Avista.

Figure A3. Electricity Generation and GHG Emissions from Idaho 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 Idaho. Overall generation grew by 11% over the 15 years, while electricity consumption grew by 7%. Natural gas generation has had particularly strong growth, from no generation in 1990 to 16% of the State's generation in 2004. Hydro-electric generation shows a decrease between 1990 and 2004, but the table masks the considerable year-by-year variation from this resource. In the 15-year period, hydro generation ranged between a low of 6,654 GWh in 1992 and a high of 14,676 GWh in 1997.

Table A2. Growth in Electricity Generation in Idaho, 1990-2004

	Generation (GWh)		Growth
	1990	2004	
Hydroelectric	9,115	8,462	-7%
Natural Gas	0	1,642	n/a
Total	9,197	10,188	11%

Source: EIA data, generation from electric sector, excludes electricity generation from combined heat and power plants in the industrial and commercial sectors.

Future Generation and Emissions

Estimating future generation and GHG emissions from Idaho 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 Idaho remains uncertain as the trends in type of new builds are influenced by many factors. Since 2004, new fossil-fuel plants in Idaho have been a mix of natural gas and wind. The Raft River plant, currently under construction, will be Idaho's first geothermal plant. Most new plant proposals rely on these natural gas and wind resources but new coal and geothermal plants have also been proposed. The proposed coal plants either use advanced combustion technology (such as the proposed CCG (clean coal gasification) 500 plant in Pocatello county) or may be located outside of the State (such as Idaho Power's proposed coal plant). Table A3 presents data on new and proposed plants in Idaho. Note that it seems unlikely that all of the proposed plants will be built prior to 2020.

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

Table A3. New and Proposed Power Plants in Idaho

	Plant Name	Fuel	Status	Capacity	Illustrative Annual		Notes
				MW	generation GWh	Emissions MMtCO ₂ e	
New plants	Bennett Mountain	Natural gas	On line 2005	162	213	0.08	
	Fossil Gulch	Wind	On line 2005	10.5	32	0.00	
	Wolverine Creek	Wind	On line 2005	64.5	198	0.00	
	Raft River Phase I	Geothermal	Construction	13.0	97	0.0	expected on line date is September 2007
Proposed plants	Burley Butte	Wind	Planned	10.5	32	0.00	planned 2006
	Danskin GT 2	Natural gas	Planned	170.0	223	0.19	planned for 2008
	Golden Valley	Wind	Planned	10.5	32	0.00	planned for 2006
	Lava Beds	Wind	Planned	18.0	55	0.00	planned for 2007
	Milner Dam Wind Park	Wind	Planned	18.0	55	0.00	planned for 2007
	Notch Butte Wind Park	Wind	Planned	18.0	55	0.00	planned for 2007
	Oregon Trail	Wind	Planned	10.5	32	0.00	planned for 2007
	Pilgrim Stage Station	Wind	Planned	10.5	32	0.00	planned for 2007
	Salmon Falls	Wind	Planned	21.0	n/a	0.00	planned for 2007
	Schwendiman	Wind	Planned	17.5	54	0.00	planned for 2007
	Thousand Springs	Wind	Planned	10.5	32	0.00	planned for 2007
	Tuana Gulch	Wind	Planned	10.5	32	0.00	planned for 2007
	CCG 500	Coal Gasification	Proposed	520.0	3,872	3.2	GHG emissions estimated with no CO ₂ sequestration. Sequestration technologies have been estimated to reduce emissions by 85% to 90%.
	Cotterel	Wind	Proposed	200.0	613	0.00	
	Raft River Phase II and III	Geothermal	Proposed	26.0	194	negligible	Air-cooled binary technology.
	Renewable Energy	Biomass	Proposed	17.5	54	negligible	Site of Boise plant idled Jul 2001.
	Shoshone Falls 4	Hydro	Proposed	50.0	350	0.00	(1) 50 MW unit. Units 1 and 2 to be retired.
Willow Creek	Geothermal	Proposed	100.0	745	negligible	Capacity is estimated total for full development.	
Idaho Power Wind	Wind	proposed in 2006 IRP	150	460	0.0	Integrated Resource Plan, 2006, projects that this will be on-line in 2012	
Idaho Power Coal, plant in Wyoming	Coal	proposed in 2006 IRP	250	1,862	1.5	Integrated Resource Plan, 2006, projects that this will be on-line in 2013 but the plant will likely be located in Wyoming.	

Sources: Northwest Power and Conservation Council. Power Plant Development in the Pacific Northwest. From www.nwccouncil.org, accessed on November 17, 2006. Idaho Power, 2006 Integrated Resource Plan. Generation estimates based on capacity factors of 0.85 for base load coal and 0.35 for wind. 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 Idaho’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 power plants in Idaho grows at 2.1% per year from 2007-2010, following growth rate in electricity sales
- Generation from power plants in Idaho grows at 2.0% per year from 2010 to 2015 and 1.0% from 2015 to 2020. This reflects the generation growth rate for the Northwest Power Pool region in Annual Energy Outlook 2006 (AEO2006).

- Generation from existing non-hydro plants is based on holding generation at 2005 levels. Generation from existing hydro-electric plants is assumed to be 10,667 GWh per year, the average generation from the last ten 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 (thus the mix of new generation discussed below would also apply to plant upgrades).
- New power plants built between 2007 and 2020 will be a mix of 50% natural gas, 40% wind and 10% geothermal or biomass. This mix is roughly based on the mix of proposed new plants, Table A3.

These assumptions lead to growth of about 350 MW of new power plant capacity by 2020.

Electricity Trade and Allocation of GHG Emissions

Idaho is part of the interconnected Western Electricity Coordinating Council (WECC) region - a vast and diverse area covering 1.8 million square miles and extending from Canada through Mexico, including all or portions of 14 western states. The inter-connected region allows electricity generators and consumers to buy and sell electricity across regions, taking advantage of the range of resources and markets. Electricity generated by any single plant enters the interconnected grid and may contribute to meeting demand throughout much of the region, depending on sufficient transmission capacity. Thus, it is challenging to define which emissions should be allocated to Idaho, and secondly in estimating these emissions both historically and into the future. Some utilities track and report electricity sales to meet consumer demand by fuel source and plant type; however, tracing sales to individual power plants may not be possible.

In 2004, Idaho had 31 entities involved in providing electricity to state customers. The State's three private utilities serve approximately 84% of the customers, and provide 88% of the electricity sales. The State's 16 electric cooperatives serve 10% of the customers and 8% of sales. Eleven public utilities account for the remaining 6% of customers and 5% of sales. The top 5 providers of retail electricity in the State are reported in Table A4.

Table A4. Retail Electricity Providers in Idaho (2004)

Entity	Ownership Type	2004 GWh
Idaho Power Co	Investor-Owned	12,575
PacifiCorp	Investor-Owned	3,262
Avista Corporation	Investor-Owned	3,239
City of Idaho Falls	Public	620
Kootenai Electric Coop Inc	Cooperative	333
Total Sales, Top Five Providers		20,029
Total, All Idaho		21,809

Source: EIA state electricity profiles

Since almost all states are part of regional trading grids, many states that have developed GHG inventories have grappled with the problem of how to account for electric sector emissions, when electricity flows across state borders. Several approaches have been developed to allocate GHG emissions from the electricity sector to individual states for inventories.

In many ways the simplest approach is *production-based* – emissions from power plants within the state are included in the state's inventory. The data for this estimate are publicly available and unambiguous. However, this approach is problematic for states that import or export significant amounts of electricity. Under a production-based approach, characteristics of Idaho electricity consumption would not be fully captured since only emissions from in-state generation would be considered.

An alternative is to estimate *consumption-based* or *load-based* GHG emissions, corresponding to the emissions associated with electricity consumed in the state. The load-based approach is

currently being considered by states that import significant amounts of electricity, such as California, Oregon, and Washington.²¹ By accounting for emissions from imported electricity, states can account for increases or decreases in fossil fuel consumed in power plants outside of the State, due to demand growth, efficiency programs, and other actions in the state. The difficulty with this approach is properly accounting for the emissions from imports and exports. Since the electricity flowing into or out of Idaho is a mix of all plants generating on the interconnected grid, it is impossible to physically track the sources of the electrons.

The approach taken in this initial inventory is a simplification of the consumption-based approach. This approach, which one could term “*Net-Consumption-based*,” estimates consumption-based emissions as in-state (production-based) emissions times the ratio of total in-state electricity consumption to in-state generation (net of losses) plus the emissions from the net imports. If the state is a net exporter of electricity, the net-consumption-based emissions are less than the production-based emissions, based on the fraction of exported electricity. If the state is a net importer of electricity, the consumption-based emissions are greater than the production-based emissions, based on the amount and GHG emission-intensity of the imports.

Emissions for net imports are calculated as net imports multiplied by an emission factor in GHG emissions per electricity generated (MtCO₂e/Megawatt-hour, MWh) for the imports. As a proxy for estimating the mix of historic and future GHG emissions for Idaho’s electricity imports, emission factors that reflect the regional fuel mix were used. The region used to reflect electricity imports is the Northwest Power Pool²² portion of the WECC (excluding Idaho’s emissions) from the AEO2006. This regional emission factor was 0.41 MtCO₂e/MWh in 2004, decreasing to 0.37 MtCO₂e/MWh in 2020, reflecting an increased regional contribution of renewables and natural gas to the electricity generation mix.

This method does not account for differences in the type of electricity that is imported or exported from the State, and as such, it provides a simplified method for reflecting the emissions impacts of electricity consumption in the State. The calculation also ignores “gross” imports – since Idaho plants have contracts to out-of-state entities, some of the in-state electricity generation will be exported and gross imports will be greater than net imports. More sophisticated methods – for example, based on individual utility information on resources used to meet loads – can be considered for further improvements to this approach. One example of the data requirements for this approach can be found in neighboring Washington State, which has developed regular fuel disclosure reporting from each of its utilities.²³

²¹ See for example, the reports of the Puget Sound Climate Protection Advisory Committee <http://www.pscleanair.org/specprog/globclim>, the Oregon Governor’s Advisory Group On Global Warming <http://egov.oregon.gov/ENERGY/GBLWRM/Strategy.shtml>, and the California Climate Change Advisory Committee, Policy Options for Reducing Greenhouse Gas Emissions From Power Imports - Draft Consultant Report <http://www.energy.ca.gov/2005publications/CEC-600-2005-010/CEC-600-2005-010-D.PDF>.

²² The Northwest Power Pool region in AEO2006 include Washington, Oregon, Idaho, Colorado, Utah and portions on Nevada, Montana and South Dakota. <http://www.eia.doe.gov/oiaf/aeo/supplement/supmap.pdf>

²³ <http://www.cted.wa.gov/site/539/default.aspx>

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 A5.

Table A5. Key Assumptions and Methods for Electricity Projections for Idaho

Electricity sales	Average annual growth of 1.9% from 2006 to 2020, based on growth rates from the three largest utilities in Idaho (see Table A1).
Electricity generation	2.1% per year from 2006-2010, based on consumption growth and proposed plants and 1.6% per year from 2010 to 2020, based on regional growth rates in AEO2006.
Transmission and Distribution losses	5% losses are assumed, based on average statewide losses, 1994-2000, (data from the US EPA Emission & Generation Resource Integrated Database ²⁴)
New Generation Sources (2006-2020)	The mix of new generation in this period roughly tracks the mix of proposed new plants in Idaho (Table A3). 50% natural gas 40% wind, and 10% biomass or geothermal
Heat Rates	The assumed heat rate for new natural gas generation is 7000 Btu/kWh, respectively, based on estimates used in similar analyses. ²⁵
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 10,667 GWh per year the average generation over the period 1996-2005. Improvements in existing facilities that lead to higher capacity factor and more generation are captured under the new generation sources.

Figure A4 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, imported electricity continues to dominate new generation throughout the forecast period (2006-2020). Generation from existing hydro plus new wind and natural gas generation show high growth, relative to levels in 2005. Overall in-state electricity generation grows at 2.2% per year from 2005 to 2020.

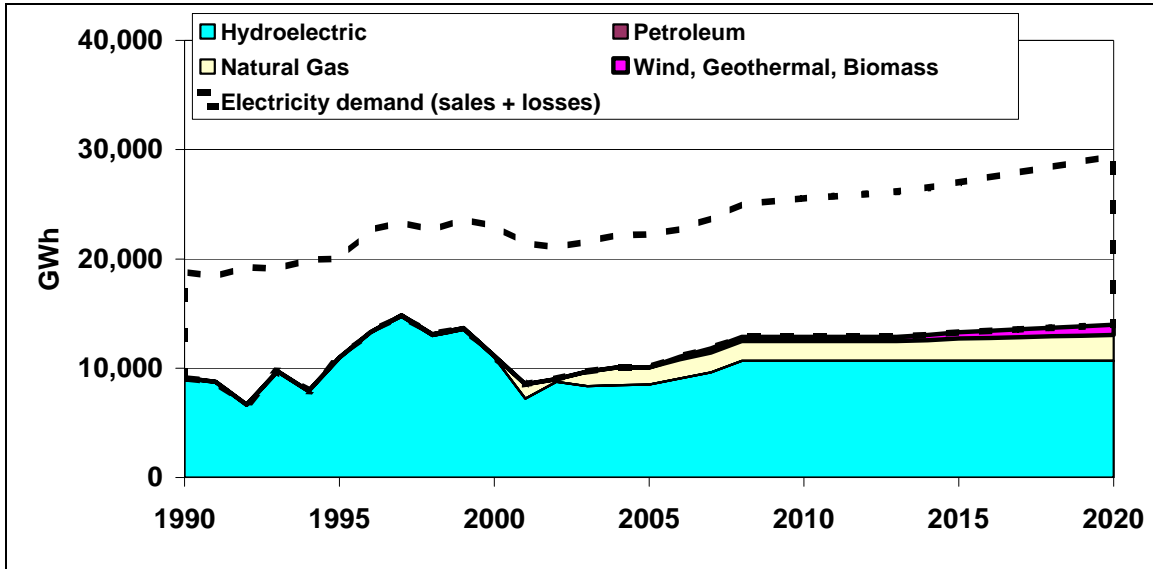
GHG emission estimates were calculated by multiplying the energy consumption by GHG emission factors by fuel. Energy consumption for 2006 to 2020 was calculated based on changes to future generation and heat rate properties described in table A6. The EPA SGIT software

²⁴ <http://www.epa.gov/cleanenergy/egrid/index.htm>.

²⁵ See, for instance, the Oregon Governor's Advisory Group On Global Warming <http://egov.oregon.gov/ENERGY/GBLWRM/Strategy.shtml>.

provided GHG emission factors by fuel for each state, consistent with factors used for EPA's national GHG inventory report.²⁶

Figure A4. Electricity Generated by Idaho Power Plants 1990-2020

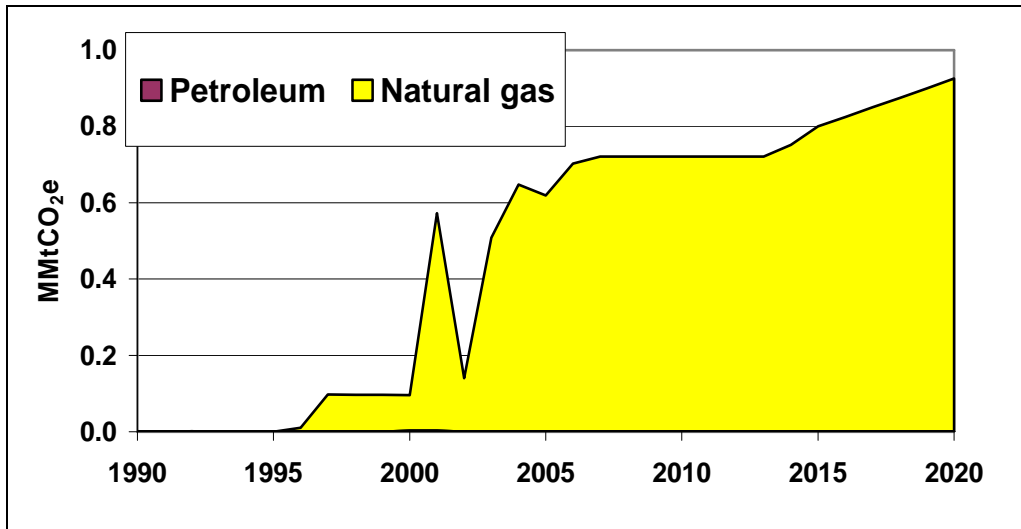


Source: 1990-2005 EIA data, 2006-2020 CCS calculations based on assumptions described above, generation from petroleum and natural gas resources are too small to be visible in the chart.

Figure A5 illustrates the GHG emissions associated with the mix of electricity generation shown in Figure A4. From 2005 to 2020, the emissions from Idaho electricity generation are projected to grow at 2.7% per year, higher than the growth in electricity generation, due to an increased fraction of generation from natural gas. As a result, the emission intensity (GHG emissions per MWh) of Idaho electricity is expected to increase from 0.061 MtCO₂/MWh in 2005 to 0.066 MtCO₂/MWh in 2020. Due to the large fraction of renewable generation (especially existing hydro-electric plants), Idaho has one of the lowest GHG emission intensities in the country for electricity generation. The large spike in GHG emissions in 2001 reflects a period of low water availability and subsequent low hydro-electric generation. Natural gas generation was relied on to provide more electricity generation. This situation lessened in 2002 but natural gas generation increased through 2005 and is assumed to increase through 2020.

²⁶ SGIT http://www.epa.gov/climatechange/emissions/state_guidance.html, National GHG inventory <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>

Figure A5. Idaho GHG Emissions Associated with Electricity Production (Production-Basis)

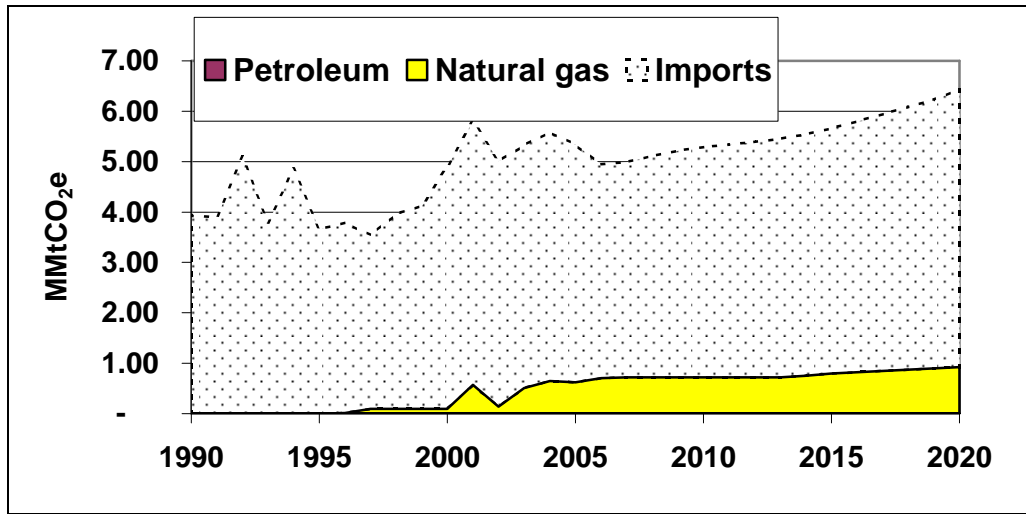


Source: CCS calculations based on approach described in text.

Note: Idaho's electric generation GHG emissions from petroleum sources are less than 0.05 MMtCO₂e and too small to be visible in the chart.

Figure A6 shows the “net-consumption-based” emissions from 1990 to 2020. Total emissions are much higher than the production-based emissions due to the GHG emissions associated with net electricity imports. Note that the vertical scale (y-axis) for Figure A6 is seven times greater than that for Figure A5. Consumption-based emissions increase by 1.2% per year from 2006 to 2020. The “spikes” in GHG emissions in 1992, 1994 and 2001 reflect years with low hydro-electricity generation (low water years). GHG emissions are estimated to increase due to additional net imports in 1992 and 1994, and due to both increased natural gas generation and electricity imports.

Figure A6. Idaho GHG Emissions Associated with Electricity Use (Net Consumption-Basis), Showing Imports



Source: CCS calculations based on approach described in text.

Note: Idaho's electric generation GHG emissions from petroleum sources are less than 0.05 MMTCO₂e and too small to be visible in the chart.

Table A6 summarizes the GHG emissions for Idaho's electric sector from 1990 to 2020. As described above, GHG emissions from net imported electricity are the main source of GHG emissions for this sector.

Table A6. Idaho GHG Emissions from Electric Sector, Production and Consumption-based estimates, 1990-2020.

(Million Metric Tons CO ₂ e)	1990	2000	2005	2010	2020
Electricity Production	0.0	0.1	0.6	0.7	0.9
Coal	0.0	0.0	0.0	0.0	0.0
CO ₂	0.0	0.0	0.0	0.0	0.0
CH ₄ and N ₂ O	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.1	0.6	0.7	0.9
CO ₂	0.0	0.1	0.6	0.7	0.9
CH ₄ and N ₂ O	0.0	0.0	0.0	0.0	0.0
Petroleum	0.0	0.0	0.0	0.0	0.0
CO ₂	0.0	0.0	0.0	0.0	0.0
CH ₄ and N ₂ O	0.0	0.0	0.0	0.0	0.0
Biomass and Geothermal (CO ₂ , CH ₄ and N ₂ O)	0.0	0.0	0.0	0.0	0.0
Net Electricity Imports (negative for exports)	3.9	4.8	4.7	4.6	5.5
Electricity Consumption-based	3.9	4.9	5.3	5.3	6.4

Note: Values that are less than 0.05 MMTCO₂e are listed as 0.0 in Table A7.

Key Uncertainties

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

- Amount and mix of new generation. Idaho's mix of new generation will depend, in part, on policies in Idaho and in states that export electricity to Idaho.
- Future generation from existing hydro-electric plants. Generation from hydro plants has varied significantly in the last 15 years and expected levels of future generation could affect plans and operation of new fossil fuel plants.
- Approach for estimating consumption-based GHG emissions. The "net-consumption-based" approach used in this analysis is a rough simplification of electricity trade that does not consider individual utility portfolios. Additional data on the historic and current mix of electricity generation used by Idaho's utilities to meet their customers' electricity demand could help refine these estimates. Refining the future GHG emission projections would likewise require additional information or assumptions on the utilities' electricity provisions.

Appendix B. Residential, Commercial, and Industrial (RCI) Fuel Combustion

Overview

Activities in the RCI²⁷ sectors produce carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions when fuels are combusted to provide space heating, process heating, and other energy applications. Carbon dioxide accounts for over 99% of these emissions on a million metric tons (MMt) of CO₂ equivalent (CO₂e) basis in Idaho. 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.²⁸ If emissions from the generation of the electricity they consume are not included, the RCI sectors are between them the third-largest source of gross greenhouse gas (GHG) emissions in Idaho. Direct use of oil, natural gas, coal, and wood in the RCI sectors accounted for an estimated 6.15 MMtCO₂e of gross GHG emissions in 2005.²⁹

Emissions and Reference Case Projections

Emissions from direct fuel use were estimated using the United States Environmental Protection Agency's (US EPA) 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.³⁰ The default data used in SGIT for Idaho are from United States Department of Energy (US DOE) Energy Information Administration's (EIA) *State Energy Data* (SED). The SGIT default data for Idaho were revised using the most recent data available, which includes: (1) 2002 SED information for all fuel types;³¹ (2) 2003 SED information for coal, and for wood and wood waste;³² (3) 2003 and 2004 SED information for natural gas;⁶ (4) 2003 and 2004 SED information for petroleum (distillate oil, kerosene and liquefied petroleum gas)

²⁷ The industrial sector includes emissions associated with agricultural energy use and fuel used by the fossil fuel production industry.

²⁸ Emissions associated with the electricity supply sector (presented in Appendix A) have been allocated to each of the RCI sectors for comparison of those emissions to the fuel-consumption-based emissions presented in Appendix B. Note that this comparison is provided for information purposes and that emissions estimated for the electricity supply sector are not double-counted in the total emissions for the state. 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 difficulty of ascribing these emissions to particular end-users. Estimates of emissions associated with the transportation sector are provided in Appendix C, and estimates of emissions associated with fossil fuel production and distribution are provided in Appendix E.

²⁹ 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 Intergovernmental Panel on Climate Change (IPCC) methodologies, and any net loss of carbon stocks due to biomass fuel use should be accounted for in the land use and forestry analysis.

³⁰ 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.

³¹ 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=IDAHO).

³² 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).

consumption;⁶ (5) 2004 electricity consumption data from the EIA's *State Electricity Profiles*;³³ and (6) 2005 natural gas consumption data from the EIA's *Natural Gas Navigator*.³⁴

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 example, the methods account for carbon stored in petrochemical feedstocks, and in liquefied petroleum gases (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.³⁵ 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 range of less than 401 degrees Fahrenheit), feedstocks (other oils with boiling ranges greater than 401 degrees Fahrenheit), LPG, lubricants, miscellaneous petroleum products, natural gas, pentanes plus,³⁶ 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),³⁷ with adjustments for Idaho's projected population and employment growth. Idaho employment data for the manufacturing (goods-producing) and non-manufacturing (commercial or services-providing) sectors were obtained from Idaho Power's *2006 Integrated Resource Plan*, which provides population and employment forecasts to 2030.³⁸ Regional employment data for the same sectors and forecast period were obtained from EIA for the EIA's Mountain region.³⁹

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 be about 1.7% annually between 2004 and 2020; this demographic trend is reflected in the growth rates for residential fuel consumption. Based on data provided in Idaho Power's *2006 Integrated Resource Plan*, over the period 2004 through 2020, commercial and industrial employment are projected to increase at compound annual rates of 2.4% and 1.4%, 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 economy — as simulated by the EIA's National Energy Modeling System — to changing fuel and electricity

³³ EIA *Electric Power Annual 2005 - State Data Tables*, (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html).

³⁴ EIA *Natural Gas Navigator* (http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SID_a.htm).

³⁵ EIIP, Volume VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels", August 2004.

³⁶ A mixture of hydrocarbons, mostly pentanes and heavier fractions, extracted from natural gas.

³⁷ EIA AEO2006 with Projections to 2030, (<http://www.eia.doe.gov/oiaf/aeo/index.html>).

³⁸ Idaho Power, *2006 Integrated Resource Plan*, Appendix C – "Economic Forecast" and "Forecast of Population, Households, and Persons per Household," Compiled and prepared by Idaho Economics, Boise, ID (<http://www.idahopower.com/2006irp/2006irpfinal.htm>).

³⁹ AEO2006 employment projections for EIA's Mountain region obtained through special request from EIA (dated September 27, 2006).

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*	2005-2010**	2010-2020**
Residential	1.9%	2.1%	1.7%
Commercial	0.8%	2.7%	2.2%
Industrial	1.7%	1.8%	1.5%
Total	1.4%	2.1%	1.8%

* 1990-2004 compound annual growth rates calculated from Idaho electricity sales by year from EIA state electricity profiles (Table 8),

http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html.

** Compound annual growth rates for total electricity sales and for each of the three sectors individually are taken from the forecast for the energy supply sector (see Appendix A).

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

	1990-2004*	2005-2010**	2010-2015**	2015-2020**
Residential				
Natural gas	6.3%	2.7%	2.3%	2.0%
petroleum	2.9%	1.3%	1.5%	1.1%
Wood	-2.6%	1.2%	-0.4%	0.0%
Coal	-14.0%	1.1%	-0.9%	-0.9%
Commercial				
natural gas	2.9%	1.9%	3.6%	2.8%
petroleum	2.0%	-0.9%	1.9%	1.4%
Wood	1.0%	0.6%	1.1%	0.7%
Coal	-10.6%	0.5%	1.1%	0.7%
Industrial				
natural gas	-0.2%	1.8%	0.0%	0.4%
petroleum	-0.8%	2.8%	1.4%	1.3%
Wood	-0.2%	3.4%	1.8%	2.1%
Coal	1.0%	1.4%	-0.3%	0.03%

* Compound annual growth rates calculated from EIA SED historical consumption by sector and fuel type for Idaho. Latest year for which EIA SED information was available for each fuel type is 2003 for coal and wood/wood waste, 2004 for petroleum, and 2005 for natural gas. Petroleum includes distillate fuel, kerosene, and liquefied petroleum gases for all sectors plus residual oil for the commercial and industrial sectors.

** Figures for growth periods starting after 2004 are calculated from AEO2006 projections for EIA's Mountain region, adjusted for Idaho's projected population for the residential sector, projections for non-manufacturing employment for the commercial sector, and projections for manufacturing employment for the industrial sector.

Population and economic forecast data are also available from the State of Idaho's Division of Financial Management that covered the period from 1992 through 2009. The forecast data available from Idaho Power was used for the reference case projections, however, because it covered the full period covered by the inventory and forecast timeframe (i.e., 1990 through

2020). For the period during which the two forecasts overlapped (i.e., 1992 through 2009), the annual growth rates for population and employment are generally similar, as illustrated in Table B3. Note that Idaho Power supplies about two-thirds of the electricity used in Idaho and the forecast information provided in Idaho Power's 2006 *Integrated Resource Plan* were also used to support the forecast assumptions for the electric supply sector provided in Appendix A.

Table B3. Comparison of Compound Annual Growth Rates from Idaho Power and Idaho Division of Financial Management Population and Economic Forecasts

Idaho Power Forecast¹						
	1990 - 1995	1995 - 2000	2000 - 2005	2005 - 2010	2010 - 2015	2015 - 2020
Population	3.1%	2.0%	1.8%	1.8%	1.7%	1.7%
Goods-Producing Employment	3.9%	2.3%	-0.2%	1.7%	0.9%	1.4%
Services-Providing Employment	4.6%	3.3%	1.9%	2.4%	2.3%	2.2%

Idaho Division of Financial Management Forecast²				
	1992 - 1995	1995 - 2000	2000 - 2005	2005 - 2009
Population	3.2%	2.0%	1.9%	2.3%
Goods-Producing Employment	5.0%	2.6%	0.1%	1.5%
Services-Providing Employment	4.9%	3.4%	2.3%	3.3%

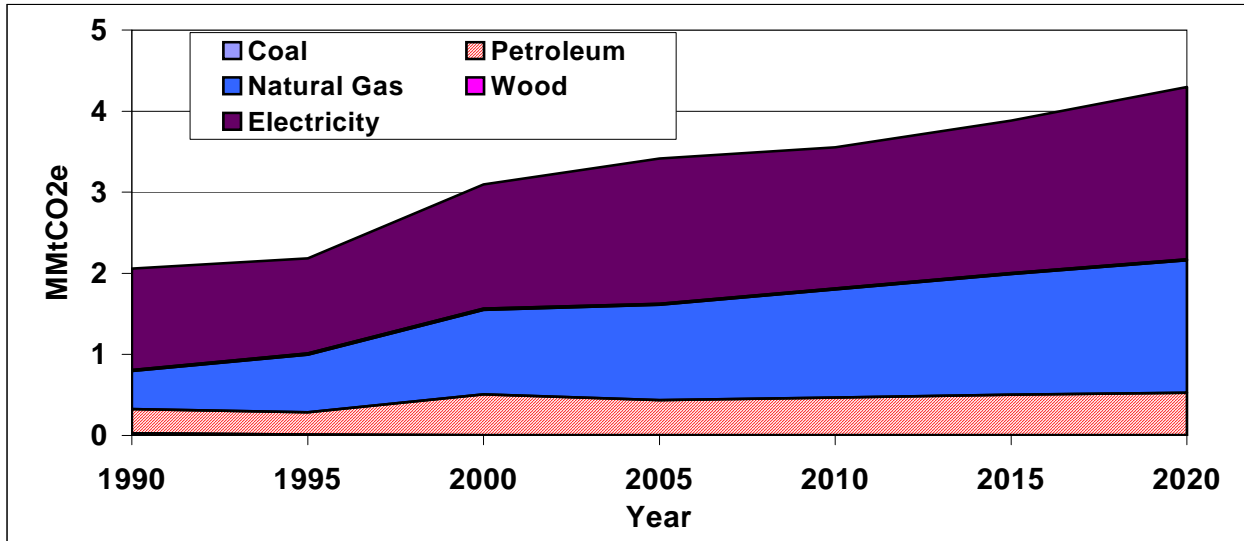
¹ Idaho Power, 2006 *Integrated Resource Plan* - Appendix C - Economic Forecast" (<http://www.idahopower.com/2006irp/2006irpfinal.htm>).

² State of Idaho, Division of Financial Management, *October 2006 Idaho Economic Forecast - Annual Tables* (<http://dfm.idaho.gov/Publications/EAB/Forecast/2006/October/iefoctober2006.html>). Data are only available for 1992 through 2009.

Results

Figures B1, B2, and B3 show historic and projected emissions for the RCI sectors in Idaho 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. During the period from 1990 through 2020, the residential sector's share of total RCI emissions from direct fuel use and electricity use ranges from 23% in 1990 to 30% from 1995 through 2020. The commercial sector's share of total RCI emissions from direct fuel use and electricity use was 21% in 1990, fell to 20% in 2005, and is projected to increase to 22% by 2020. The industrial sector's share of total RCI emissions from direct fuel use and electricity use was 56% in 1990, declined to 50% in 2005, and is projected to decline further to 47% by 2020. Emissions associated with the generation of electricity to meet RCI demand from 1990 through 2020 accounts for about, on average, 52% of the emissions for the residential sector, 57% of the emissions for the commercial sector, and 34% of the emissions for the industrial sector. Natural gas consumption is the next-highest source of emissions for all three sectors, accounting for about 34% of total emissions in the residential sector, 31% for the commercial sector, and 24% for the industrial sector when averaged over the 1990 to 2020 period.

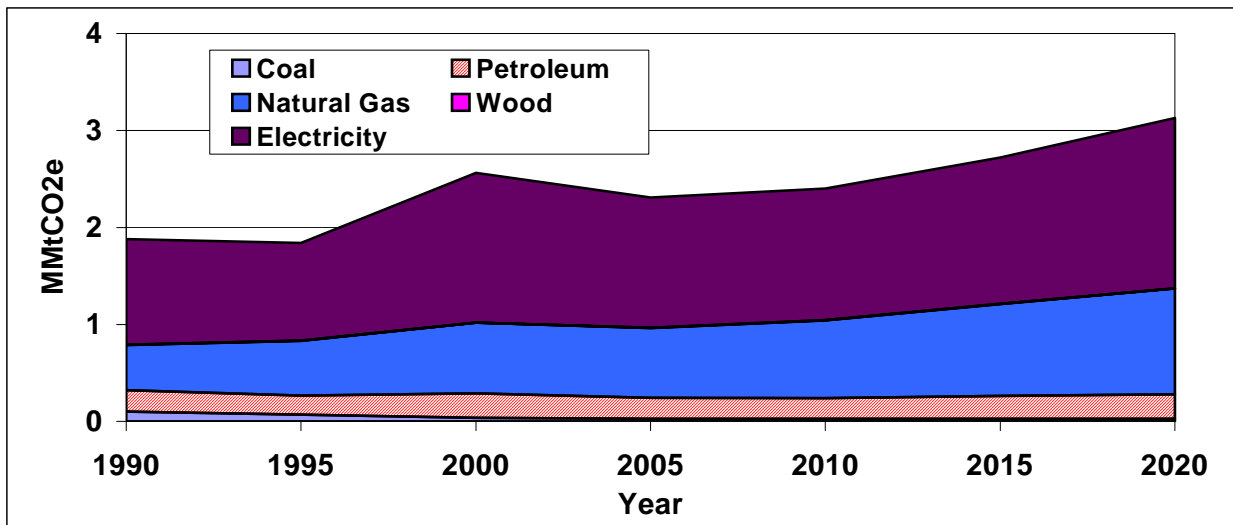
Figure B1. Residential Sector GHG Emissions from Fuel Consumption



Source: CCS calculations based on approach described in text.

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

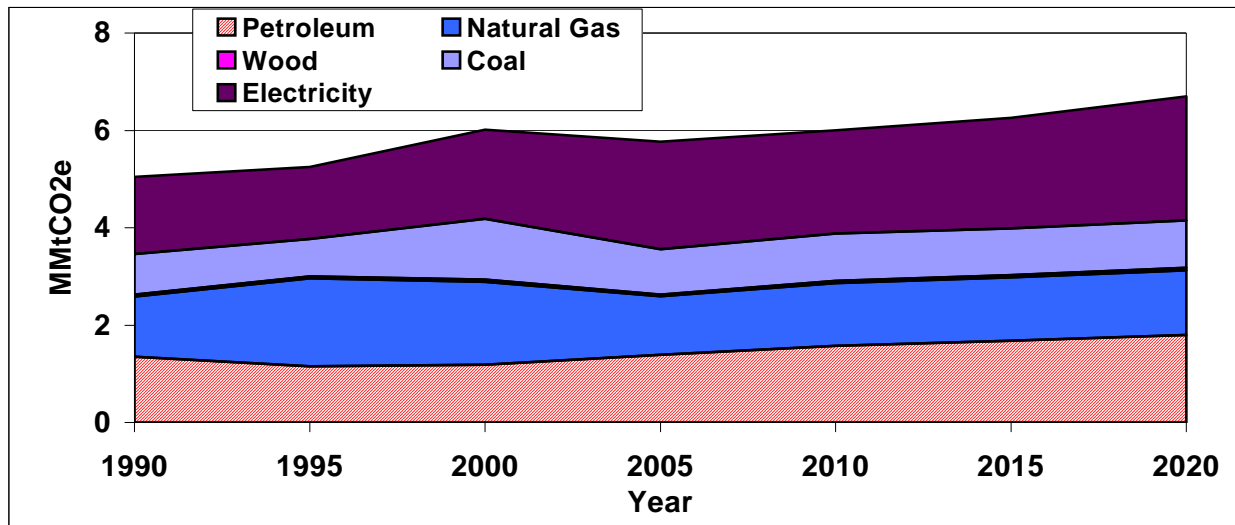
Figure B2. Commercial Sector GHG Emissions from Fuel Consumption



Source: CCS calculations based on approach described in text.

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

Figure B3. Industrial Sector GHG Emissions from Fuel Consumption



Source: CCS calculations based on approach described in text.

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 2.1 MMtCO_{2e}, and are estimated to increase to about 4.3 MMtCO_{2e} by 2020. Emissions associated with the generation of electricity to meet residential demand accounted for about 61% of total residential emissions in 1990, and are estimated to decline to about 49% of total residential emissions by 2020. In 1990, natural gas consumption accounted for about 23% of total residential emissions, and gas use is estimated to account for about 38% of total residential emissions by 2020. Residential sector emissions associated with the use of coal, petroleum, and wood in 1990 were about 0.34 MMtCO_{2e} combined, and accounted for about 16% of total residential GHG emissions. By 2020, emissions associated with the consumption of these three fuels are estimated to be 0.54 MMtCO_{2e} and to account for 13% of total residential sector emissions.

For the 15-year period 2005 to 2020, residential-sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 1.2% and 2.2%, respectively. Emissions associated with the use of petroleum and wood are expected to increase annually by about 1.3% and 0.2%, respectively, and emissions associated with the use of coal are expected to decline by about -0.4% annually. Total GHG emissions for this sector increase by an average of about 1.2% annually over the 15-year period.

For the commercial sector, emissions from electricity and direct fuel use in 1990 were about 1.9 MMtCO_{2e}, and are estimated to increase to about 3.1 MMtCO_{2e} by 2020. Emissions associated with the generation of electricity to meet commercial sector demand accounted for about 58% of total commercial emissions in 1990, and are estimated to decline slightly, to about 56% of total commercial emissions, by 2020. In 1990, natural gas consumption accounted for about 25% of total commercial emissions, and is estimated to account for about 35% of total commercial emissions by 2020. Commercial-sector emissions associated with the use of coal, petroleum, and wood in 1990 were about 0.32 MMtCO_{2e} combined, and accounted for about 17% of total

commercial emissions. For 2020, emissions associated with the consumption of these three fuels are estimated to be 0.28 MMtCO_{2e}, and to account for 9% of total commercial sector emissions.

For the 15-year period 2005 to 2020, commercial-sector GHG emissions associated with the use of electricity and natural gas are expected to increase at average annual rates of about 1.8% and 2.8%, respectively. Emissions associated with the use of coal, petroleum, and wood are expected to increase at annual rates of about 0.8%, 1.0%, and 0.8%, respectively. Total GHG emissions for this sector increase by an average of about 2.1% annually over the 15-year period.

For the industrial sector, emissions in 1990 were about 5.0 MMtCO_{2e}, and are estimated to increase to about 6.7 MMtCO_{2e} by 2020. Emissions associated with the generation of electricity to meet industrial demand accounted for about 31% of total industrial emissions in 1990 and are estimated to increase to about 38% of total industrial emissions by 2020. In 1990, natural gas consumption accounted for about 25% of total industrial emissions and is estimated to account for about 20% of total industrial emissions by 2020. Industrial sector emissions associated with the use of coal, petroleum, and wood in 1990 were about 2.2 MMtCO_{2e} combined, and accounted for about 44% of total industrial emissions. For 2020, emissions associated with the consumption of these three fuels are estimated to be 2.8 MMtCO_{2e} and to account for 42% 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 1.0% and 0.7%, respectively. Emissions associated with the use of coal, petroleum, and wood are expected to increase annually by about 0.3%, 1.7%, and 2.4%, respectively. Total GHG emissions for this sector increase at an average rate of about 1.0% 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 Mountain modeling region scaled for Idaho 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 Idaho 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, and thereby affect emissions estimates.
- The exception to the AEO2006 assumption of no large changes in prices or fuels consumption is the AEO2006 reference-case projections for industrial coal consumption. The AEO2006 model's forecast for the EIA's Mountain region assumes that new coal-to-liquids plants would be constructed near active coal mines when low-sulfur distillate oil prices reach high enough levels to make coal-to-liquids processing economic. Plants are

assumed to be co-production plants with generation capacity of 758 MW and the capability of producing 33,200 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle (electricity generation) plant, first converting the coal feedstock to gas, and then subsequently converting the synthetic gas to liquid hydrocarbons using the Fisher-Tropsch process. As a result, AEO2006 projections assume a rather significant increase in coal consumption by the coal-to-liquids industrial sector starting in 2011. For the EIA's Mountain region, this sector accounts for 17.5% of total coal consumption in 2011 and 63% of total coal consumption in 2020, with an annual growth rate of 26% from 2011 to 2020.⁴⁰ This increase in coal consumption, associated with the installation of coal-to-liquids plants starting in 2011, was excluded from the industrial coal consumption forecasts for Idaho because it is considered to represent technology that is beyond the "business-as-usual" assumptions associated with the reference case projections for the industrial coal consumption sector.

⁴⁰ Coal Market Module of the National Energy Modeling System 2006, as described in *Assumptions to the Annual Energy Outlook 2006, Coal Market Module*, Report #: DOE/EIA-0554(2006), March 2006
<http://www.eia.doe.gov/oiaf/aeo/assumption/index.html>

Appendix C. Transportation Energy Use

Overview

The transportation sector is one of the largest sources of GHG emissions in Idaho. Carbon dioxide accounts for about 84 percent of transportation GHG emissions from fuel use. Most of the remaining GHG emissions from the transportation sector are due to N₂O emissions from gasoline 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.^{41,42} 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.⁴³ The default VMT data in SGIT were replaced with state-level annual VMT from the Idaho Transportation Department (ITD).⁴⁴ State-level VMT was allocated to vehicle types using the default vehicle mix data in SGIT.

Onroad vehicle gasoline and diesel emissions were projected based on VMT projections developed by ITD⁴ and growth rates developed from national vehicle type VMT forecasts reported in EIA's *Annual Energy Outlook 2006* (AEO2006). 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 estimates of Idaho 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 ITD estimates for total VMT in the State for each year to yield the vehicle type VMT estimates and compound annual average growth rates. These results are displayed in Tables C2 and C3, respectively.

⁴¹ 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.

⁴² 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.

⁴³ Energy Information Administration, State Energy Consumption, Price, and Expenditure Estimates (SED), http://www.eia.doe.gov/emeu/states/_seds.html

⁴⁴ Supplied by Chris Ramsdell, Idaho Department of Environmental Quality.

**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 from ITD, adjusted by fuel efficiency improvement projections from AEO2006. Other onroad fuels projected using Mountain 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 ITD, VMT allocated to vehicle types using default data in SGIT.</p> <p>Reference Case Projections (2003 – 2020) VMT projection from ITD.</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.</p> <p>Reference Case Projections (2003 – 2020) Aircraft projected using prime supplier sales volumes from EIA, aircraft operations projections from Federal Aviation Administration (FAA), and jet fuel efficiency improvement projections from AEO2006. Rail and marine gasoline projected based on historical data.</p>

Table C2. Idaho Vehicle Miles Traveled Compound Annual Growth Rates

Vehicle Type	2002-2005	2005-2010	2010-2015	2015-2020
Heavy Duty Diesel Vehicle	3.94%	3.10%	2.27%	1.77%
Heavy Duty Gasoline Vehicle	2.64%	1.58%	1.72%	1.34%
Light Duty Diesel Truck	5.43%	6.64%	6.09%	5.83%
Light Duty Diesel Vehicle	5.43%	6.64%	6.09%	5.83%
Light Duty Gasoline Truck	1.24%	1.66%	1.12%	0.63%
Light Duty Gasoline Vehicle	1.24%	1.66%	1.12%	0.63%
Motorcycle	1.24%	1.66%	1.12%	0.63%

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 EIA's *Annual Energy Outlook* (AEO). These projections suggest onroad fuel consumption growth rates of 0.4% per year for gasoline and 2.7% per year for diesel between 2002 and 2020.

Gasoline consumption estimates for 1990-2002 were adjusted by subtracting ethanol consumption. Projections for ethanol consumption in Idaho were not available; therefore, ethanol consumption was assumed to remain at the 2002 level (0% 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 were projected from 2002-2005 using historical prime supplier volumes of jet fuel and aviation gasoline in Idaho from EIA.⁴⁵ Emissions were projected from 2005 to 2020 using general aviation and commercial aircraft operations for 2005 to 2020 from the Federal Aviation Administration's (FAA) Terminal Area Forecast System⁴⁶ and national aircraft fuel efficiency forecasts. To estimate changes in jet fuel consumption, itinerant aircraft operations from air carrier, air taxi/commuter, and military aircraft were first summed for each year of interest. The jet fuel projections 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. Because AEO2006 does not estimate fuel efficiency changes for general aviation aircraft, forecast changes in aviation gasoline consumption were based solely on the projected number of itinerant general aviation aircraft operations in Nevada, which was obtained from the FAA source noted above. These projections resulted in the compound annual growth rates shown in Table C3.

⁴⁵ Prime Supplier Volumes, Petroleum Navigator, Energy Information Administration, http://tonto.eia.doe.gov/dnav/pet/pet_cons_prim_dcu_SSD_a.htm.

⁴⁶ Terminal Area Forecast, Federal Aviation Administration, <http://www.apo.data.faa.gov/main/taf.asp>.

Table C3. Idaho Aviation Fuel Compound Annual Growth Rates

Fuel	2002-2005	2005-2010	2010-2015	2015-2020
Aviation Gasoline	0.00%	1.62%	2.06%	1.95%
Jet Fuel	0.99%	0.85%	0.39%	0.26%

For the rail and marine sectors, 1990 – 2004 estimates are based on SGIT methods and fuel consumption from EIA. Emissions from these sources were projected based on the historical 1990-2004 data, which result in 2005-2020 compound annual growth rates of 0.01% for rail and 1.4% for marine gasoline.

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 C4 shows how EIA divides gasoline and diesel fuel consumption between the transportation, commercial, and industrial sectors.

Table C4. EIA Classification of Gasoline and Diesel Consumption

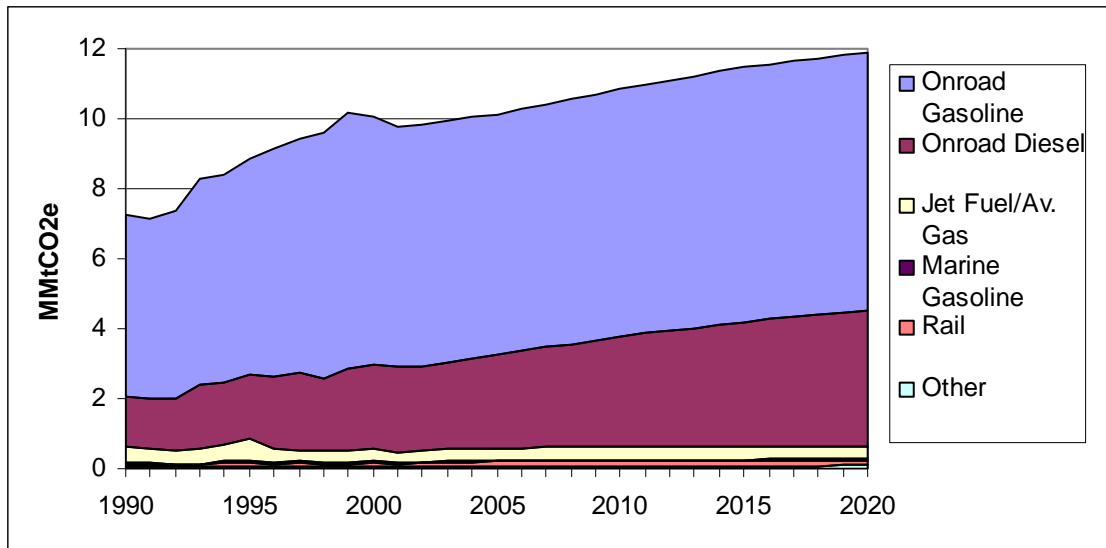
Sector	Gasoline Consumption	Diesel Consumption
Transportation	Highway vehicles, marine	Vessel bunkering, military use, railroad, highway vehicles
Commercial	Public non-highway, miscellaneous use	Commercial use for space heating, water heating, and cooking
Industrial	Agricultural use, construction, industrial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

Results

As shown in Figure C1, onroad gasoline and diesel consumption accounts for the largest share of transportation GHG emissions. Emissions from onroad gasoline vehicles increased by about 32% from 1990-2002 to cover 70% of total transportation emissions in 2002. GHG emissions from onroad diesel fuel consumption increased by 72% from 1990 to 2002, and by 2002 accounted for 24% of GHG emissions from the transportation sector. Emissions from aviation fuels decreased by 26% from 1990-2002 to cover less than 4% of total transportation emissions in 2002. Emissions from all other categories combined (marine gasoline, locomotives, natural gas and LPG, and oxidation of lubricants) contributed only 2% of total transportation emissions in 2002.

GHG emissions from all onroad vehicles combined are projected to increase by only 21% between 2002 and 2020, due to a 28% increase in VMT during this period and projected fuel efficiency improvements. Most of this growth is predicted to occur in the diesel sector, with onroad gasoline consumption projected to increase by only 7%, and emissions from onroad diesel consumption projected to increase by 61% between 2002 and 2020. Emissions from aviation fuels are projected to increase by 11% between 2002 and 2020.

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



Source: CCS calculations based on approach described in text.

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 2002 and 2020 was not taken into account (due to a lack of data).

Uncertainties in Aviation Fuel Consumption

The jet fuel and aviation gasoline fuel consumption from EIA is actually fuel *purchased* in the state, and therefore includes fuel consumed during state-to-state flights and international flights. The fuel consumption associated with international air flights should not be included in the state inventory; however, data were not available to subtract this consumption from total jet fuel estimates. Another uncertainty associated with aviation emissions is the use of general aviation forecasts to project aviation gasoline consumption. General aviation aircraft consume both jet fuel and aviation gasoline, but fuel specific data were not available.

Appendix D. Industrial Processes

Overview

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

- Carbon Dioxide (CO₂) from:
 - Production of cement and lime;
 - Consumption of limestone, dolomite, and soda ash;
- Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆) from semiconductor manufacture;
- 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 Idaho include the following:

- Nitrous oxide (N₂O) from nitric and adipic acid production;
- SF₆ from magnesium production and processing;
- CO₂ from soda ash production;
- PFCs from aluminum production; and
- HFCs from HCFC-22 production.

Emissions and Reference Case Projections

GHG emissions for 1990 through 2005 were estimated using the United States Environmental Protection Agency's (US EPA) State Greenhouse Gas Inventory Tool (SGIT) software and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for this sector.⁴⁷ Table D1 identifies for each emissions source category the information needed for input into SGIT to calculate emissions, the data sources used for the analysis described here, and the historical years for which emissions were calculated based on the availability of data. The Idaho Department of Environmental Quality (IDDEQ) provided data for annual clinker production and annual lime production for 1999, 2002, and 2005. Table D1 provides additional details on how the data provided were used to calculate historical emissions for these two categories.

⁴⁷ GHG emissions were calculated using SGIT, with reference to EIIP, Volume VIII: Chapter. 6. "Methods for Estimating Non-Energy Greenhouse Gas Emissions from Industrial Processes", August 2004. Referred to as "EIIP" below.

Table D1. Approach to Estimating Historical Emissions

Source Category	Time Period	Required Data for SGIT	Data Source
Cement Manufacturing - Clinker Production	1990 - 2005	Metric tons (Mt) of clinker produced each year.	Idaho Department of Environmental Quality (IDDEQ) provided annual clinker production data for one plant (Ash Grove Cement) for 1999, 2002, and 2005. Data for 1999 were used as a surrogate for data for 1990, 1995, and 2000.
Lime Manufacture	1990 - 2005	Mt of high-calcium lime and dolomitic produced each year.	IDDEQ provided total lime production for two plants owned by TASC0 for 1999, 2002, and 2005. Data for 1999 were used as surrogate for data for 1990, 1995, and 2000. Information on the type of lime manufactured was not available; assumed production was for high-calcium lime.
Limestone and Dolomite Consumption	1990 - 2002	Mt of limestone and dolomite consumed.	Used default consumption data available in SGIT for 1994 through 2002. Default data for 1990 through 1993 were not available in SGIT. 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 document.
Soda Ash Consumption	1990 - 2002	Mt of soda ash consumed.	<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 for 1990 through 2020 from Idaho Power, <i>2006 Integrated Resource Plan</i> , Appendix C – "Forecast of Population, Households, and Persons per Household," Compiled and prepared by Idaho Economics, Boise, Idaho (http://www.idahopower.com/2006irp/2006irpfinal.htm). -- US 1990-2000 population from US Census Bureau (http://www.census.gov/popest/archives/EST90INTE RCENSAL/US-EST90INT-01.html). -- US 2000-2005 population from US Census Bureau (http://www.census.gov/population/projections/SummaryTabA1.xls).
Semiconductor Manufacturing	1990 - 2002	State and national value of semiconductor shipments for NAICS code 334413 (Semiconductor and Related Device Manufacturing). Method uses ratio of state-to-national value of semiconductor shipments to estimate state's proportion of national emissions for 1990 - 2002.	National emissions from US EPA 2005 "Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003" (http://www.epa.gov/climatechange/emissions/usgginv_archive.html). Value of shipments from U.S Census Bureau's "1997 Economic Census" (http://www.census.gov/econ/census02/). Note: Idaho data for NAICS code 334413 withheld in 2002 Economic Census.
Electric Power T&D Systems	1990 - 2002	Emissions from 1990 to 2003 based on the national emissions per kWh and state's electricity use provided in SGIT.	National emissions per kWh from US EPA 2005 "Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003" (http://www.epa.gov/climatechange/emissions/usgginv_archive.html).

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.

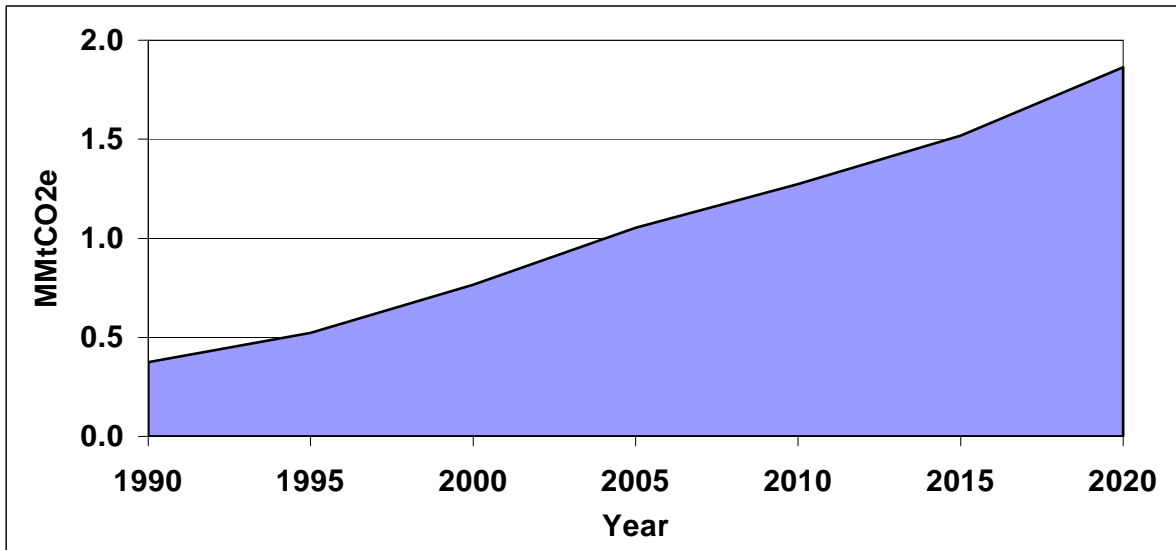
Table D2. Approach to Estimating Projections

Source Category	Time Period	Projection Assumptions	Data Source	Annual Growth Rates (%)			
				2000 to 2005	2005 to 2010	2010 to 2015	2015 to 2020
Cement Manufacturing - Clinker Production	2006 - 2020	Compound annual growth rate for Idaho's goods-producing sector. The goods-producing sector includes employment in the natural resources and mining, construction, and manufacturing sectors.	Idaho Power, 2006 <i>Integrated Resource Plan</i> , Appendix C – "Economic Forecast," Compiled and prepared by Idaho Economics, Boise, Idaho (http://www.idahopower.com/2006irp/2006irpfinal.htm).	None, actual data used for 2000 and 2005	1.7	0.9	1.4
Lime Manufacture	2006 - 2020	Ditto	Ditto	Ditto	1.7	0.9	1.4
Limestone and Dolomite Consumption	2003 - 2020	Ditto	Ditto	-0.2	1.7	0.9	1.4
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 I, 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/TMP6si9htrvca.htm).	15.8	7.9	5.8	5.3
Semiconductor Manufacturing	2003 - 2020	National growth rate (based on aggregate for all stewardship program categories provided in referenced data source)	US Department of State, US <i>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
Electric Power T&D Systems	2003 - 2020	Ditto	Ditto	3.3	-6.2	-9.0	-2.8

Results

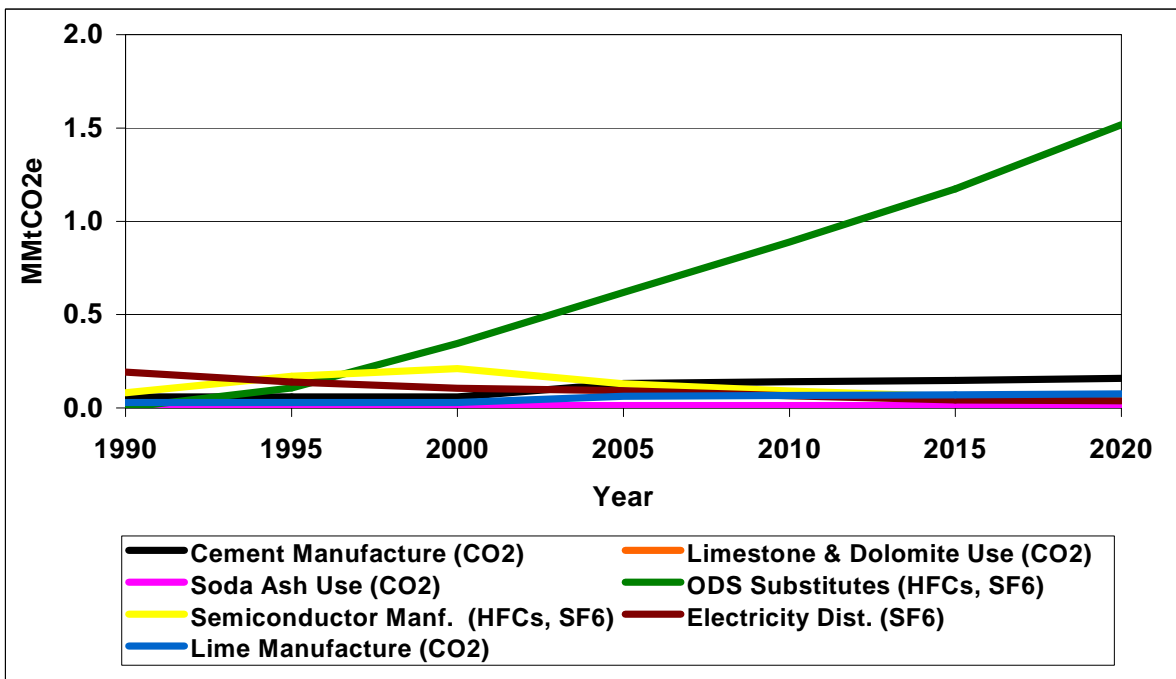
Figures D1 and D2 show historic and projected emissions for the industrial processes sector from 1990 to 2020. Total gross GHG emissions were about 0.8 MMTCO₂e in 2000 (2% of total gross Idaho GHG emissions), rising to about 1.9 MMTCO₂e in 2020 (5% of total gross GHG emissions). Emissions from the overall industrial processes category are expected to grow rapidly, as shown in Figures D1 and D2, with emissions growth primarily associated with increasing use of HFCs and PFCs in refrigeration and air conditioning equipment.

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



Source: CCS calculations based on approach described in text.

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



Source: CCS calculations based on approach described in text.

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*.⁴⁸ 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. GHG-equivalent emissions from the use of ODS substitutes in Idaho were calculated using the default methods in SGIT (see dark green line in Figure D2). Emissions have increased from 0.0014 MMtCO₂e in 1990 to about 0.36 MMtCO₂e in 2000, and are expected to increase at an average rate of 7.7% 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.

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 Idaho from 1990 to 2002 were estimated based on the estimates of emissions per kWh from the US EPA GHG inventory and Idaho'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 Idaho. The decline in SF₆ emissions in the future reflects expectations of future actions by the electric industry to reduce these emissions. Relative to total industrial non-combustion process emissions, SF₆ emissions from electrical equipment are low (about 0.19 MMtCO₂e in 1990 and 0.04 MMtCO₂e in 2020), and therefore, appear at the bottom of the graph because of scaling effects in Figure D2.

Semiconductor Manufacture

Emissions of SF₆ and HFCs from the manufacture of semiconductors have experienced declines since 2000 (see yellow line in Figure D2). Emissions for Idaho from 1990 to 2002 were estimated based on the default estimates provided in SGIT, which uses the ratio of the state-to-national value of semiconductor shipments to estimate the state's proportion of national emissions from the US EPA GHG inventory (US EPA 2005 *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003*). 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 Idaho. The decline in emissions in the future reflects expectations of future actions by the semiconductor industry to reduce these emissions.

Relative to total industrial non-combustion process emissions, emissions associated with semiconductor manufacturing are low (about 0.08 MMtCO₂e in 1990 and 0.05 MMtCO₂e in 2020), and therefore, appear at the bottom of the graph because of scaling effects in Figure D2.

⁴⁸ 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 types. For the US national inventory, a detailed stock vintaging model was used to track ODS substitutes uses and emissions, but this modeling approach has not been completed at the state level.

Clinker Production for Cement Manufacture

Idaho has one cement plant (Ash Grove Cement Company) that produces clinker (an intermediate product from which finished Portland and masonry cement are made). Clinker production releases CO₂ when calcium carbonate (CaCO₃) is heated in a cement kiln to form lime (calcium oxide) and CO₂ (see Chapter 6 of the EIIP guidance document). Emissions are calculated by multiplying annual clinker production and annual production of masonry cement by emission factors for these processes. The clinker production data for the plant was summed and entered into the SGIT to calculate GHG emissions (see black line in Figure D2). Information on masonry cement production for the plant was not available. The employment growth rate for Idaho's goods-producing sector was used to project emissions to 2020. As shown in Figure D2, emissions increase slightly from 0.13 MMtCO₂e in 2005 to 0.16 MMtCO₂e in 2020, reflecting an overall average annual increase of about 1.3% over that time period.

Lime Manufacture

Idaho has two plants (both owned by TASCOS) that produce lime. Lime is a manufactured product that is used in many chemical, industrial, and environmental applications including steel making, construction, pulp and paper manufacturing, and water and sewage treatment. Lime is manufactured by heating limestone (mostly CaCO₃) in a kiln, creating calcium oxide and CO₂. The CO₂ is driven off as a gas and is normally emitted to the atmosphere, leaving behind a product known as quicklime. Some of this quicklime undergoes slaking (combining with water), which produces hydrated lime. The consumption of lime for certain uses, specifically the production of precipitated CaCO₃ and refined sugar, results in the reabsorption of some airborne CO₂ (see Chapter 6 of the EIIP guidance document).

Emissions are estimated by multiplying the amount of high-calcium and dolomitic lime produced by CO₂ emission factors for high-calcium and dolomitic lime. Information on the type of lime produced by the two plants in Idaho was not available. For this initial analysis, it was assumed that both plants produce high-calcium lime for the purpose of calculating emissions. The high-calcium lime production data for both plants were summed and entered into the SGIT to calculate statewide GHG emissions from this source (see dark blue line in Figure D2). The employment growth rate for Idaho's goods-producing sector was used to project emissions to 2020. As shown in Figure D2, emissions increase slightly from 0.06 MMtCO₂e in 2005 to 0.08 MMtCO₂e in 2020, reflecting an overall average annual increase of about 1.3% over that time period.

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.⁴⁹ Recent historical data for Idaho were not available from the USGS; consequently, the default data

⁴⁹ 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).

provided in SGIT were used to calculate emissions for Idaho from the use of these materials (see orange line in Figure D2). The employment growth rate for Idaho's goods-producing sector was used to project emissions from 2003 through 2020. Relative to total industrial non-combustion process emissions, emissions associated with limestone and dolomite consumption are low (about 0.007 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 Idaho for 1990 through 1993, and therefore emissions were not estimated for these years.

Soda Ash Consumption

Commercial soda ash (sodium carbonate) is used in the manufacture of many consumer products such as glass, soap and detergents, paper, textiles, and food. CO₂ is also released when soda ash is consumed (see Chapter 6 of the 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 US 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 0.01 MMtCO₂e in 1990 and 0.014 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:

- Data for all of the historical years could not be obtained because of time and resource constraints. The inventory can be improved upon in the future by obtaining actual production and consumption data for all of the historical years.
- IDDEQ noted that there is one plant (J.R. Simplot - Don Siding in Pocatello, Idaho) that may manufacture nitric acid. IDDEQ did not have information to verify if this plant has either manufactured in the past or currently manufactures nitric acid. Future work should include an assessment to verify if this plant has manufactured nitric acid. If this plant has manufactured nitric acid, the production and control data for the plant should be obtained to calculate emissions associated with this sector. Note that the 100-year global warming potential for N₂O emissions, which are associated with the manufacture of nitric acid, is 310 times more potent than that of CO₂; consequently, emissions for the industrial processes category could be significantly underestimated (on a MMtCO₂e basis) if nitric acid manufacture in Idaho (if it takes place) is not included in the inventory and forecast.
- Since emissions from industrial processes are determined by the level of production and the production processes of a few key industries—and in some cases, 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 Idaho manufacturers in these industries, and on the specific nature of the production processes used in Idaho.

- 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; Idaho-specific estimates are currently unavailable. In addition, emissions through 2020 and beyond 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.
- 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); and
 - Silicon Carbide Production (CH₄).

The CO₂ emissions from the above CO₂ sources (other than 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 other categories.

Appendix E. Fossil Fuel Industries

Overview

This appendix reports the greenhouse gas (GHG) emissions that are released during the production, processing, transmission, and distribution of fossil fuels. Known as fugitive emissions, these are methane (CH₄) and carbon dioxide (CO₂) emissions released via leakage and venting from 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 GHG emissions in 2004.⁵⁰ Emissions associated with energy consumed by these processes are included in Appendix B, Residential, Commercial, and Industrial Sectors.

Oil, Gas and Coal Production

Idaho's oil and gas industry is limited to two product pipelines that traverse the state from refineries in Montana and Utah⁵¹, as well as one LNG storage compressor station.⁵² There are no active wells, refineries or processing plants. Idaho has no producing coal mines, nor coal bed CH₄ production or proved reserves, as reporting by the EIA.⁵³

Natural Gas Industry Emissions

Emissions of CH₄ can occur at many stages of production, processing, transmission, and distribution of oil and gas. Since there is no oil or gas production in Idaho, fugitive emissions from this sector are released primarily from over 8,000 miles of natural gas transmission and distribution pipelines in the state.⁵⁴ As there are no regulatory requirements to track CH₄ emissions from oil and gas systems, estimates based on emissions measurements in Idaho are not possible at this time.

The State Greenhouse Gas Inventory Tool (SGIT), developed by the US EPA, facilitates estimation of state-level GHG emissions.⁵⁵ 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 EIA⁵⁶ and American Gas Association's annual publication *Gas*

⁵⁰ "The U.S. Inventory of Greenhouse Gas Emissions and Sinks", US EPA, 2005.

⁵¹ "Petroleum Profile: Idaho" US DOE Energy Information Administration website, October 2006, Accessed at <<http://tonto.eia.doe.gov/oog/info/state/id.html>> &

⁵² "US LNG Markets and Uses" EIA Office of Oil and Gas 2003, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf

Map on pg 2 shows 1 LNG Storage facility in ID

Per Bruce Wilding (Program and Technical Manager, Idaho National Laboratory) This singular LNG plant came into operation in 1996. <<http://www.inl.gov/lng/projects/nozzles.shtml>>

⁵³ US DOE Energy Information Administration website, December 2006.

⁵⁴ Data from Gas Facts.

⁵⁵ Methane emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, Volume VIII: Chapter. 5. "Methods for Estimating Methane Emissions from Natural Gas and Oil Systems", March 2005.

⁵⁶ "Petroleum Navigator" and "Natural Gas Navigator", US DOE Energy Information Administration website, November 2006, <http://www.eia.doe.gov>

*Facts.*⁵⁷ Methane emissions were estimated using SGIT, with reference to the EIIP guidance document.

Future projections of CH₄ emissions from oil and gas systems are calculated based on the following key drivers:

- Consumption – See Appendix A, Electricity, and Appendix B, Residential, Commercial and Industrial Sector for assumptions used in projecting natural gas consumption in Idaho. Based on those assumptions, Idaho’s natural gas consumption is projected to grow at an annual average rate of 1.9% between 2006 and 2020.⁵⁸
- Production – Simple assumptions were made for natural gas transmission and transport.

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

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

	Approach to Estimating Historical Emissions		Approach to Estimating Projections
<i>Activity</i>	<i>Required Data for SGIT</i>	<i>Data Source</i>	<i>Projection Assumptions</i>
Natural Gas Drilling and Field Production	Number wells	EIA	There is no natural gas production in Idaho, as reported by the EIA.
	Miles of gathering pipeline	Gas Facts	
Natural Gas Processing	Number gas processing plants	EIA ⁵⁹	Idaho does not have any operating gas processing plants.
Natural Gas Transmission	Miles of transmission pipeline	Gas Facts ¹⁰	Emissions assumed to follow State gas consumption trend - annual average growth rate of 1.9% between 2006 and 2020. ⁶⁰
	Number of gas transmission compressor stations	EIIP ⁶¹	
	Number of gas storage compressor stations	EIIP ⁶²	
	Number of LNG storage compressor stations	Idaho National Laboratory ⁶³	

⁵⁷ American Gas Association “Gas Facts, A Statistical Record of the Gas Industry” Referenced annual publications from 1992 to 2004.

⁵⁸ Based on US DOE regional projections and electric sector growth assumptions (see Appendix A and B).

⁵⁹ EIA reports no gas processing facilities in Idaho.

⁶⁰ Based on US DOE regional projections and electric sector growth assumptions (see Appendix A and B).

⁶¹ Number of gas transmission compressor stations = miles of transmission pipeline x 0.006 EIIP. Volume VIII: Chapter 5. March 2005.

⁶² Number of gas storage compressor stations = miles of transmission pipeline x 0.0015 EIIP. Volume VIII: Chapter 5. March 2005.

⁶³ “US LNG Markets and Uses” EIA Office of Oil and Gas 2003, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf

Map on pg 2 shows 1 LNG Storage facility in ID

Per Bruce Wilding (Program and Technical Manager, Idaho National Laboratory) Idaho’s only LNG plant started operating in 1996. <http://www.inl.gov/lng/projects/nozzles.shtml>

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

Natural Gas Distribution	Miles of distribution pipeline	Gas Facts ¹⁰	Distribution emissions follow State gas consumption trend - annual average growth rate of 1.9% between 2006 and 2020. ⁶⁴
	Total number of services	Gas Facts	
	Number of unprotected steel services	Ratio estimated from 2002 data ⁶⁵	
	Number of protected steel services	Ratio estimated from 2002 data ¹⁶	
Oil Production	Annual production	EIA ⁶⁶	There is no oil production in Idaho, as reported by EIA.
Oil Refining	Annual amount refined	EIA ⁶⁷	There are no oil refineries in Idaho, as reported by EIA.
Oil Transport	Annual oil transported	Unavailable, assumed oil refined = oil transported	Emissions from transport of oil in Idaho are assumed to be negligible.

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

Results

Table E2 displays the estimated CH₄ emissions from the fossil fuel industry in Idaho from 1990 to 2005, with projections to 2020. Emissions from this sector grew by 30% from 1990 to 2005 and are projected to increase by a further 32% between 2005 and 2020. Emissions are based solely on natural gas transmission and distribution systems.

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

(Million Metric Tons CO ₂ e)	1990	1995	2000	2005	2010	2015	2020
Fossil Fuel Industry	0.32	0.39	0.45	0.42	0.46	0.51	0.55
Natural Gas Industry	0.32	0.39	0.45	0.42	0.46	0.51	0.55
Transmission (CH ₄)	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Distribution (CH ₄)	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Oil Industry (CH ₄)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Mining (CH ₄)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note that 0.0 in the above table indicates no activity in this sector.

⁶⁴ Based on US DOE regional projections and electric sector growth assumptions (see Appendix A and B).

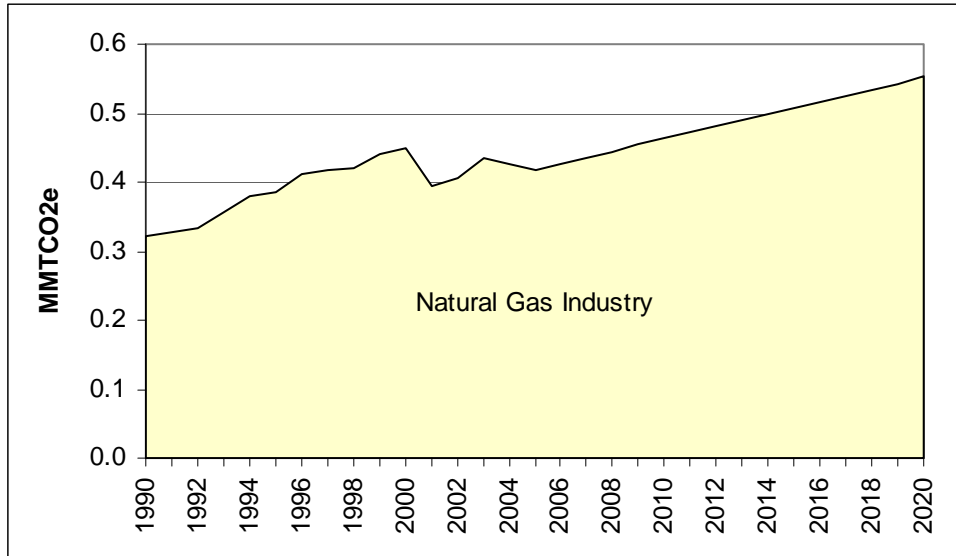
⁶⁵ Gas Facts reported unprotected and protected steel services for 2002-3, but only total services for other years. Therefore the ratio of unprotected and protected steel services in 2003 was assumed to be the ratio for all other years (0.325 for protected services and 0 for unprotected services). This 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.

⁶⁶ EIA and Petroleum Supply Annual report no crude oil production in Idaho.

⁶⁷ There is no refining data for the state of Idaho.

Error! Reference source not found.Figure E1 displays the CH₄ emissions from natural gas systems in Idaho, on a MMtCO₂e basis.

Figure E1. Fossil Fuel Industry Emission Trends (MMtCO₂e)



Source: CCS calculations based on approach described in text.

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 pipelines or local facilities, uncertainties remain.
- Any future transmission lines through Idaho would impact fugitive emission projections.
- Any future production of coal, oil or natural gas in Idaho would increase fugitive emission levels.
- Other uncertainties include potential emission reduction improvements to pipeline technologies.

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 related to agricultural practices (combustion of fossil fuels to power 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 than in other animals because of digestive activity in the large fore-stomach to break down grasses and other high-fiber feeds. 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 (or oxygen-free) anaerobic conditions. Under aerobic conditions, N₂O emissions are the dominant GHG emissions of concern. Emissions estimates from manure management are based on estimates of the volumes of manure that are stored and treated in 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 inventories of emissions from agricultural soils.

The management of agricultural soils can result in N₂O emissions and in fluxes of carbon dioxide (CO₂) that make soils net emitters or net sinks of carbon. In general, soil amendments that add nitrogen to soils can also result in N₂O emissions. Nitrogen additions drive underlying soil nitrification and de-nitrification 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 and sewage sludge application to soils, nitrogen fixation, and cultivation of histosols (high organic soils, such as wetlands or peatlands). 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 Idaho.

The net flux of CO₂ in or out of 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. Conversely, 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 SGIT and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.⁶⁸ 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.⁶⁹

Data on crop production in Idaho from 1990 to 2005 and on 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.⁷⁰ 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 Idaho 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 Idaho from 1990 to 2005 from the USDA NASS were used to calculate N₂O emissions from crop residues and crops that use nitrogen (i.e., nitrogen fixation) and CH₄ emissions from agricultural residue burning through 2005. Emissions for the other agricultural crop production practices categories (i.e., synthetic and organic fertilizers) were calculated through 2002.

Data were not available to estimate nitrogen released by the cultivation of histosols (i.e., the number of acres of high organic content soils). As discussed in the following section for soil carbon, the Natural Resources Ecology Laboratory at Colorado State University estimated 0.07 MMtCO₂ of emissions from cultivated high organic content soils in Idaho for 1997. Therefore, future work should attempt to obtain data to estimate N₂O emissions from cultivated histosol soils in Idaho to improve the emission estimates for this category.

⁶⁸ GHG emissions were calculated using SGIT, with reference to Emission Inventory Improvement Program, 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.

⁶⁹ Revised 1996 Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories, published by the National Greenhouse Gas Inventory Program of the IPCC, <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, <http://www.ipcc-nggip.iges.or.jp/public/gp/english/>.

⁷⁰ USDA, NASS http://www.nass.usda.gov/Statistics_by_State/Idaho/index.asp.

Agricultural residue burning is conducted in Idaho. 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 Idaho, 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. These annual growth rates were applied to the most recent year for which historical emissions were estimated (i.e., 2002 for enteric fermentation, manure management, agricultural soils – livestock, and fertilizers; 2005 for agricultural crop residues and nitrogen fixing crops). The annual growth factors for fertilizers, agricultural crop residues, and nitrogen-fixing crops were developed based on the annual growth rate in historical emissions (MMtCO₂e basis) for these categories in Idaho (i.e., 1990 to 2002 for fertilizers and 1990 to 2005 for crop residues and nitrogen fixing crops).

Table F1. Annual Growth Rates Applied for the Agricultural Sector

Agricultural Category	Annual Growth Rates				Basis for Annual Growth Rate*
	2003-2005	2005-2010	2010-2015	2015-2020	
Enteric Fermentation	3.1%	2.5%	0.0%	0.0%	Idaho Department of Agriculture.
Manure Management	5.9%	4.4%	0.0%	0.0%	Idaho Department of Agriculture.
Agricultural Burning	0.0%	0.0%	0.0%	0.0%	Assumed no growth.
Agricultural Soils – Direct Emissions					
Fertilizers	-2.3%	-2.3%	-2.3%	-2.3%	Historical emissions for 1990-2002.
Crop Residues	1.3%	1.3%	1.3%	1.3%	Historical emissions for 1990-2005.
Nitrogen-Fixing Crops	2.3%	2.3%	2.3%	2.3%	Historical emissions for 1990-2005.
Histosols	0.0%	0.0%	0.0%	0.0%	No historical data available.
Livestock	0.4%	0.4%	0.0%	0.0%	Idaho Department of Agriculture.
Agricultural Soils – Indirect Emissions					
Fertilizers	-2.3%	-2.3%	-2.3%	-2.3%	Historical emissions for 1990-2002.
Livestock	2.1%	2.1%	0.0%	0.0%	Idaho Department of Agriculture.
Leaching/Runoff	-0.2%	-0.2%	-0.2%	-0.2%	Historical emissions for 1990-2002.

* The Idaho Department of Agriculture provided guidance for forecasting dairy cattle populations (see text for details) that were applied in preparing the forecasts for enteric fermentation, manure management, and application of livestock manure to soils. For the other categories shown in this table, the compound annual growth rates were calculated using the growth rate in historical emissions (MMtCO₂e basis) from 1990 through the most recent year of data, and applied to the latest year of data to forecast emissions to 2020.

For enteric fermentation and manure management, historical emissions were driven primarily by the relatively high growth (about 7% annually) in the dairy cattle population from 1990 through 2002. The beef cattle population remained relatively constant with an annual growth rate of 0.15% from 1990 through 2002 and a slight decline of about -0.4% from 1997 through 2002. Swine populations declined by about 8% during the 12-year period and by about 10% during the 5-year period covering 1997 through 2002. Based on information provided by a contact with the Idaho Department of Agriculture, it was assumed that the dairy cattle population for Idaho would

increase by 5.5% annually from 2002 through 2010.⁷¹ The contact with the Idaho Department of Agriculture thought that the dairy cattle population will level off significantly after 2010, but noted that forecast data for the 2010 to 2020 period are not available.

Using the information on future growth in the dairy cattle population obtained from the Idaho Department of Agriculture, and given the historical decline in the beef cattle and swine populations in Idaho, CCS calculated emissions for each of the enteric fermentation and manure management categories for 2003 through 2020 by holding populations for all animal categories (except for dairy cattle) at 2002 levels. For dairy cattle, the population was assumed to grow by 5.5% annually from 2003 through 2010 and then the population was held constant at the 2010 population level for 2011 through 2020. The growth factors shown in Table F1 were then calculated from the total emissions calculated for the enteric fermentation and manure management categories and then applied to total emissions in 2002 for each of these categories to forecast emissions through 2020.

For the agricultural soils – livestock category, annual growth factors were calculated based on the historical 12-year trend in emissions for 1990 through 2002 to estimate emissions for 2003 through 2010. Emissions for 2011 through 2020 were held constant at 2010 levels based on the assumptions discussed for the enteric fermentation and manure management categories.

Soil Carbon

Net carbon fluxes from agricultural soils have been estimated by researchers at the Natural Resources Ecology Laboratory at Colorado State University, and are reported in the *U.S. Inventory of Greenhouse Gas Emissions and Sinks*⁷² and the *U.S. Agriculture and Forestry Greenhouse Gas Inventory*. The estimates are based on the IPCC methodology for soil carbon adapted to conditions in the US preliminary state-level estimates of CO₂ fluxes from mineral soils and emissions from the cultivation of organic soils were reported in the *U.S. Agriculture and Forestry Greenhouse Gas Inventory*.⁷³ Currently, these are the best available data at the state-level for this category. The inventory did not report state-level estimates of CO₂ emissions from limestone and dolomite applications; hence, this source is not included in this inventory at present.

Carbon dioxide fluxes resulting from specific management practices were reported. These practices include: conversions of cropland resulting in either higher or lower soil carbon levels;

⁷¹ Mr. Marv Patten, Idaho Department of Agriculture, provided dairy cattle population estimates for 2002 through 2010 based on permit applications received or expected to be received by the department for expanding existing or building new dairy operations. Growth factors were calculated from the population data to estimate the growth in emissions associated with the dairy cattle contribution to total emissions for the enteric fermentation and manure management categories.

⁷² *U.S. 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>.

⁷³ *U.S. Agriculture and Forestry Greenhouse Gas Inventory: 1990-2001*. Global Change Program Office, Office of the Chief Economist, US Department of Agriculture. Technical Bulletin No. 1907, 164 pp. March 2004. http://www.usda.gov/oce/global_change/gg_inventory.htm; the data are in appendix B table B-11. The table contains two separate IPCC categories: “carbon stock fluxes in mineral soils” and “cultivation of organic soils.” The latter is shown in the second to last column of Table F2. The sum of the first nine columns is equivalent to the mineral soils category.

additions of manure; participation in the Federal Conservation Reserve Program (CRP); and cultivation of organic soils (with high organic carbon levels). For Idaho, Table F2 shows a summary of the latest estimates available from the USDA, which are for 1997. These data show that changes in agricultural practices are estimated to result in a net sink of 1.19 MMtCO₂e/yr in Idaho. Since data are not yet available from USDA to make a determination of whether the emissions are increasing or decreasing, the net sink of 1.19 MMtCO₂e/yr is assumed to remain constant.

Table F2. GHG Emissions from Soil Carbon Changes Due to Cultivation Practices (MMtCO₂e)

Changes in cropland			Changes in Hayland				Other			Total ⁴
Plowout of grassland to annual cropland ¹	Cropland management	Other cropland ²	Cropland converted to hayland ³	Hayland management	Cropland converted to grazing land ³	Grazing land management	CRP	Manure application	Cultivation of organic soils	Net soil carbon emissions

Based on USDA 1997 estimates. Parentheses indicate net sequestration.

¹ Losses from annual cropping systems due to plow-out of pastures, rangeland, hayland, set-aside lands, and perennial/horticultural cropland (annual cropping systems on mineral soils, e.g., corn, soybean, cotton, and wheat).

² Perennial/horticultural cropland and rice cultivation.

³ Gains in soil carbon sequestration due to land conversions from annual cropland into hay or grazing land.

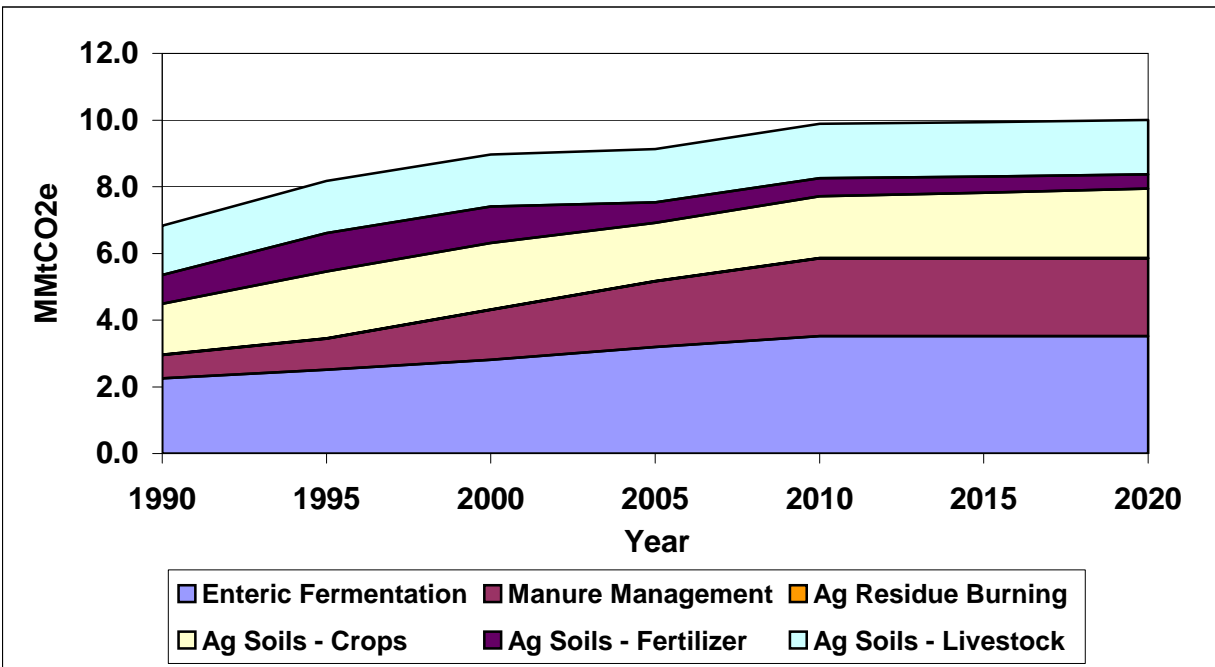
⁴ Total does not include change in soil organic carbon storage on federal lands, including those that were previously under private ownership, and does not include carbon storage due to sewage sludge applications.

Results

As shown in Figure F1, gross GHG emissions from agricultural sources range between about 6.8 and 10 MMtCO₂e from 1990 through 2020, respectively. In 1990, enteric fermentation accounted for about 33% (2.3 MMtCO₂e) of total agricultural emissions and is estimated to account for about 35% (3.5 MMtCO₂e) of total agricultural emissions in 2020. The manure management category accounted for 10% (0.7 MMtCO₂e) of total agricultural emissions in 1990 and is estimated to account for about 23% (2.3 MMtCO₂e) of total agricultural emissions in 2020. The agricultural soils category shows 1990 emissions accounting for 56% (3.9 MMtCO₂e) of total agricultural emissions and 2020 emissions estimated to be about 41% (4.1 MMtCO₂e) of total agricultural emissions. Including the CO₂ sequestration from soil carbon changes, the historic and projected emissions for the agriculture sector on a net basis would range between about 5.6 and 8.8 MMtCO₂e/yr from 1990 through 2020, respectively.

As previously discussed, the growth in the dairy cattle population from 1990 through 2010 accounts for the increase in emissions shown in Figure F1 for the enteric fermentation, manure management, and agricultural soils – livestock categories. Forecast information for livestock populations in Idaho after 2010 are not available; therefore, emissions associated with the livestock categories were held constant at 2010 levels for the period covering 2011 through 2020.

Figure F1. Gross GHG Emissions from Agriculture



Source: CCS calculations based on approach described in text.

Notes: Ag Soils – Crops category includes: incorporation of crop residues and nitrogen fixing crops (no cultivation of histosols estimated in Idaho); emissions for agricultural residue burning are too small to be seen in this chart. Soil carbon sequestration is not shown (see Table F2).

Agricultural burning emissions were estimated to be relatively large for Idaho based on the SGIT activity data (relative to the US total) (0.01 MMtCO₂e/yr from 1990 to 2002). For Idaho, this category accounts for about 0.14% and 0.1% of Idaho’s total gross GHG emissions associated with the agricultural sector in 1990 and 2020, respectively. Emissions for this category account for about one-half of the national emissions included in the USDA Inventory which, relative to other agricultural categories, reports a low level of residue burning emissions (0.02 MMtCO₂e). Thus, even though these initial emission estimates using the SGIT are low relative to emissions associated with the other agricultural categories in Idaho, the emission estimates for agricultural burning in Idaho using the SGIT methodology are inconsistent with other data and should be refined using actual activity data for Idaho, if available.

The only standard IPCC source categories missing from this report are N₂O emissions from the cultivation of histosol soils and CO₂ emissions from limestone and dolomite application. Estimates for Idaho were not available; however, the USDA’s national estimate for soil liming is about 9 MMtCO₂e/yr.⁷⁴

⁷⁴ U.S. Agriculture and Forestry Greenhouse Gas Inventory: 1990-2001. Global Change Program Office, Office of the Chief Economist, US Department of Agriculture.

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 that are dependent on several variables, including manure production levels, volatile solids contents of manures, 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 emissions associated with changes in agricultural soil carbon levels, the only data currently available are for 1997. When newer data are released by the USDA, these should be reviewed to represent current conditions as well as to assess trends. In particular, given the potential for some CRP acreage to retire and possibly return to active cultivation prior to 2020, the current size of the CO₂ sink could be appreciably affected. As mentioned above, emission estimates for soil liming have not been developed for Idaho.

Another contributor to uncertainty in the emission estimates is the projection assumptions. For the fertilizers, agricultural crop residues, and nitrogen-fixing crops categories, 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. In addition, for the enteric fermentation and manure management categories, the assumption that livestock populations will not change from 2002 levels (except for the dairy cattle population) is highly uncertain. Future work should focus on improving on the growth rate assumptions for the dairy industry in Idaho.

Although the agricultural burning emissions estimated using the SGIT method are low relative to emissions associated with the other agricultural categories covered by this sector, the emissions account for about one-half of the US total estimated for this category. Future work on the agricultural sector should include efforts to improve the estimates for agricultural burning.

Appendix G. Waste Management

Overview

GHG emissions from waste management include:

- Solid waste management – methane (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, carbon dioxide (CO₂), and nitrous oxide (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 US EPA SGIT software and the US EPA Landfill Methane Outreach Program (LMOP) landfills database⁷⁵ as starting points to estimate emissions. The LMOP data serve as input data to estimate annual waste emplacement for each landfill modeled 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 final CH₄ emissions.

IDDEQ provided a list of landfills in the state with annual waste emplacement data that was used to supplement the LMOP database. These additional data included information on many sites that were not present in the LMOP database, as well as updated information on sites that were present in the database (e.g. waste emplacement data, information on controls). In the combined LMOP and IDDEQ dataset for Idaho, there are over 100 sites represented (both open and closed landfills). Two of these sites collect landfill gas for use in a landfill gas to energy (LFGTE) plant (Fighting Creek Farm and Hidden Hollow). The rest of the sites were assumed to be uncontrolled.

Annual waste emplacement was only available for one year, so this rate was assumed for all years that the landfill was operating. For sites where the years of operation were not available, CCS assumed that the landfill opened prior to 1961. Waste emplacement data was not available for 12 landfills. For landfills with waste emplacement values of 0.00 tons per day in the IDDEQ list, the waste emplacement was assumed to be 0.001 tons per day.

CCS performed two different runs of SGIT to estimate emissions from municipal solid waste (MSW) landfills: (1) uncontrolled landfills, and (2) landfills with a landfill gas collection system and LFGTE plant. SGIT produced annual estimates through 2005 for each of these landfill categories. CCS then performed some post-processing of the landfill emissions to account for landfill gas controls (at LFGTE sites) and to project the emissions through 2020. For the

⁷⁵ 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.

controlled landfills, CCS assumed that the overall methane collection and control efficiency is 75%.⁷⁶ 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).

Growth rates were estimated by using the historic (1995-2005) growth rates of emissions in both the controlled and uncontrolled landfill categories. The period from 1995 to 2005 was used since there were a large number of landfill closures during the period in 1994 (which could have affected waste management practices). Hence, the post-1995 period is thought to be most representative of waste emplacement rates in the future and subsequent emissions. The annual growth rates are: 2.0% for uncontrolled sites and 2.4% for LFGTE landfills.

CCS used the SGIT default for industrial solid waste landfills. This default is based on national data indicating that industrial landfilled waste is emplaced at approximately 7 percent of the rate of MSW emplacement. We assumed that this additional industrial waste emplacement occurs beyond that already addressed in the emplacement rates for MSW sites described above. Due to a lack of data, no controls were assumed for industrial waste landfilling. For industrial landfills, the overall growth rate in MSW emissions from 1995 to 2005 (2%/yr) was used to project emissions to 2020 (based on the assumption that industrial waste landfilling will continue to grow at the same rate as MSW landfilling overall).

Solid Waste Combustion

There are no solid waste incinerators operating in Idaho; however, IDDEQ has estimated a significant level of residential waste open burning (e.g., backyard burn barrels). IDDEQ provided estimates of MSW open burning from their 2005 area source criteria pollutant inventory. The IDDEQ estimates were based on the EPA's burnable waste factor (8.56 lbs/household), which is based on national data. The estimated tons of waste burned for 2005 was scaled to other years based on rural population data. Emissions were projected to 2020 based on 2005-2020 population projections.⁷⁷

Wastewater Management

GHG emissions from municipal 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 G1 below. A revised value for the percentage of state residents on septic (60%) was provided by IDDEQ. Municipal wastewater emissions were based on population projections for 2005-2020 for a growth rate of 1.7% per year.

⁷⁶ As per EPA's AP-42 Section on Municipal Solid Waste Landfills:
<http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf>.

⁷⁷ 2006 Integrated Resource Plan, Idaho Power, <http://www.idahopower.com/2006irp/2006irpfinal.htm>.

Table G1. SGIT Key Default Values for Municipal Wastewater Treatment

Variable	Default Value
BOD	0.065 kg /day-person
Amount of BOD anaerobically treated	16.25%
CH ₄ emission factor	0.6 kg/kg BOD
Idaho 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/.

For industrial wastewater emissions, SGIT provides default assumptions and emission factors for three industrial sectors: Fruits & Vegetables, Red Meat & Poultry, and Pulp & Paper. IDDEQ provided 2005 data on wastewater flow and COD for 20 plants in the fruit and vegetable sector and 2 plants in the meat and poultry sector. Emissions for 2005 were scaled to other years based on County Business Patterns employment data.⁷⁸ Employment data for SIC 2030 and NAICS 3114 were used for the fruit and vegetable sector; employment data for SIC 2010 or NAICS 3115 were used for the meat and poultry sector. Employment data was only available for 1993-2004, so employment estimates were forecasted for 2005 and back-casted for 1990-1992 based on the 1993-2004 data. Emissions were projected to 2020 based on the 1990-2005 annual growth rate (-1.5%).

Results

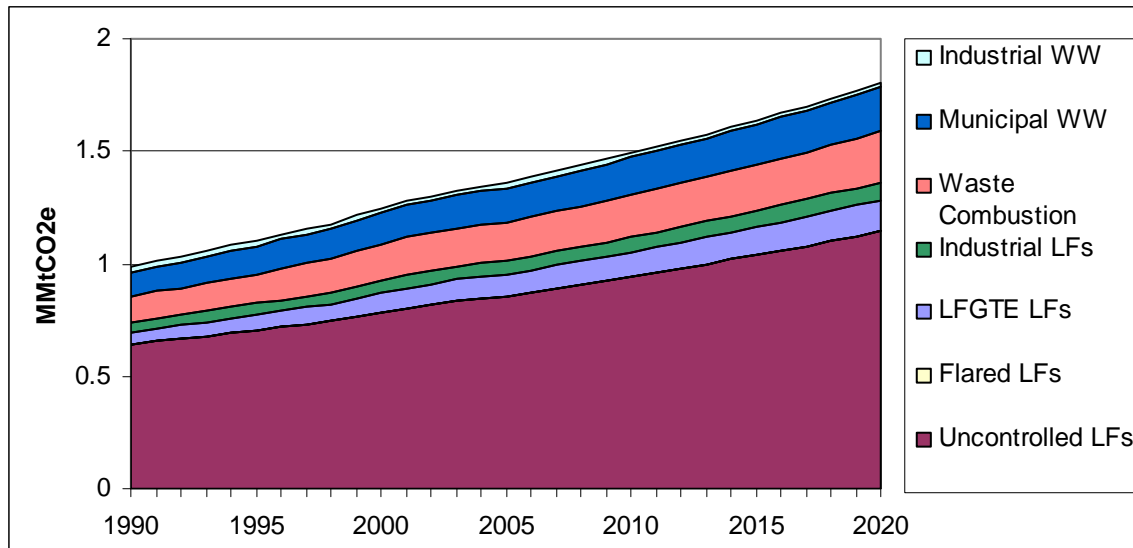
Figure G1 shows the emission estimates for the waste management sector. Overall, the sector accounts for 1.5 MMtCO₂e in 2005. By 2020, emissions are expected to grow to 1.8 MMtCO₂e/yr. The largest contributor to waste management emissions is the solid waste sector, in particular, uncontrolled municipal landfills. In 2005, uncontrolled and LFGTE municipal landfills accounted for 63% and 7% of total waste management emissions, respectively. By 2020, the contribution from these sites is expected to be about 64% and 8%.

In 2005, about 11% of the waste management sector emissions were contributed by municipal wastewater treatment systems and 2% of emissions were contributed by industrial wastewater. Note that these estimates are based on the default parameters listed in Table G1 above, and might not adequately account for existing controls or management practices (e.g. anaerobic digesters served by a flare or other combustion device). By 2020, municipal and industrial wastewater treatment sectors are expected to contribute about 11% and 1% of the waste management sector emissions.

Emissions from waste combustion accounted for 13% of total waste management emissions in 2005 and are projected to account for 12% in 2020.

⁷⁸ County Business Patterns, US Census Bureau, <http://www.census.gov/epcd/cbp/view/cbpview.html>.

Figure G1. Idaho GHG Emissions from Waste Management



Source: CCS calculations based on approach described in text.

Notes: LF – landfill; WW – wastewater; LFGTE – landfill gas to energy; there are no flared landfills in Idaho.

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 (since each site that is currently controlled was modeled as always being controlled, the historic emissions estimates are lower than they should be as a result). The modeling also does not account for uncontrolled sites that will need to apply controls during the period of analysis due to triggering the 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 Idaho. For this reason, emissions could be slightly underestimated for landfills.

For industrial landfills, emissions were estimated using national defaults (with industrial landfill wastes buried at 7% of the rate of MSW emplacement). It could be that the available MSW emplacement data within the combined LMOP data used to model the MSW emissions already captures industrial LF emplacement. As with overall MSW landfill emissions, industrial landfill emissions are projected to increase between 2005 and 2020. Hence, the industrial landfill inventory and forecast has a significant level of uncertainty and should be investigated further. For example, the existence of active industrial landfills that are not already represented in the LMOP database should be determined. If these sites do not exist and the existing municipal waste emplacement data are thought to include industrial wastes, then the separate estimate for industrial landfill emissions can be excluded from the inventory.

According to IDDEQ, about 75% of wastewater biosolids are applied to soils. In this inventory, N₂O emissions associated with these biosolids are included in the wastewater sector. Since most of the emissions probably occur after land application, these emissions could be included in the

agricultural soils sector instead. These emissions are estimated to equal 0.06 MMtCO₂e in 2005. Other key uncertainties with the wastewater sector are associated with the application of SGIT default values for the parameters listed in Table G1 above (e.g. the fraction of BOD that is anaerobically decomposed). The SGIT defaults for emission factors used to estimate wastewater emissions were derived from national data. Waste combustion emissions were also based on a factor derived from national data.

Appendix H. Forestry

Overview

Forestland emissions refer to the net carbon dioxide (CO₂) flux⁷⁹ from forested lands in Idaho, which account for about 41% of the state's land area.⁸⁰ The dominant forest types in Idaho are Douglas fir forests which make up about 34% of forested lands and Fir-Spruce forests which make up another 24%. Other important forest types are Ponderosa pine, Lodgepole pine, and Hemlock-Sitka spruce forests.

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

Inventory and Reference Case Projections

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 *U.S. Inventory of Greenhouse Gas Emissions and Sinks*.⁸¹ The national estimates are compiled from state-level data. The Idaho forest CO₂ flux data in this report come from the national analysis and are provided by the USFS.

The forest CO₂ flux methodology relies on input data in the form of plot level forest volume statistics from the Forest Inventory and Analysis (FIA). FIA data on forest volumes are converted to values for ecosystem carbon stocks (i.e., the amount of carbon stored in forest carbon pools) using the FORCARB2 modeling system. Coefficients from FORCARB2 are applied to the plot level survey data to give estimates of C density (Mg per hectare) for a number of separate C pools.

Carbon dioxide flux is estimated as the change in carbon mass for each carbon pool over a specified time frame. Forest volume data from at least two points in time are required. The change in carbon stocks between time intervals is estimated at the plot level for specific carbon pools (Live Tree, Standing Dead Wood, Under-story, Down & Dead Wood, Forest Floor, and Soil Organic Carbon) and divided by the number of years between inventory samples. Annual increases in carbon density reflect carbon sequestration in a specific pool; decreases in carbon

⁷⁹ "Flux" refers to both emissions of CO₂ to the atmosphere and removal (sinks) of CO₂ from the atmosphere.

⁸⁰ Total forested acreage is 21.9 million acres. Acreage by forest type available from the USFS at: <http://www.fs.fed.us/ne/global/pubs/books/epa/states/ID.htm>. The total land area in Idaho is 53.5 million acres <http://www.50states.com/idaho.htm>

⁸¹ *U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004* (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006. <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

density reveal CO₂ emissions or carbon transfers out of that pool (e.g., death of a standing tree transfers carbon from the live tree to standing dead wood pool). The amount of carbon in each pool is also influenced by changes in forest area (e.g. an increase in area could lead to an increase in the associated forest carbon pools and the estimated flux). The sum of carbon stock changes for all forest carbon pools yields a total net CO₂ flux for forest ecosystems.

In preparing these estimates, USFS estimates the amount of forest carbon in different forest types as well as different carbon pools. The different forests include those in the national forest (NF) system and those that are not federally-owned (private and other public forests). USFS also provides information on forests categorized as being either woodlands (forests with low productivity) and non-woodlands (e.g. timberlands or productive forest systems). In Idaho, there is very little of the woodlands forest type (e.g. pinyon-juniper forests).

Carbon pool data for two periods are used to estimate CO₂ flux for each pool. The data shown in Table H1 are based on the most recent estimates from the USFS and are included in the 2005 estimates in EPA's national GHG inventory. CCS provided totals with and without the soil carbon pool. Discussions with USFS have indicated that the soil carbon pool estimates carry a high level of uncertainty and in many cases might not be statistically different than zero.⁸²

Table H1. Forest Carbon Flux Estimates for Idaho

Forest Pool	Carbon Flux (MMtC)	Carbon Flux (MMtCO ₂)
Live Tree (above ground)	1.4	5.1
Live Tree (below ground)	0.3	1.1
Standing Dead & Down Dead	0.1	0.4
Forest Floor	0.2	0.7
Soil Carbon	-0.2	-0.7
Harvested Wood Products	-1.0	-3.7
Totals	0.8	2.9
Totals (excluding soil carbon)	1.0	3.6

Totals may not sum exactly due to independent rounding.

Data source: Jim Smith, USFS, personal communications with S. Roe, CCS, October 2006 and February 2007.

In addition to the forest carbon pools, additional carbon stored as biomass is removed from the forest for the production of durable wood products. Carbon remains stored in the products pool or is transferred to landfills where much of the carbon remains stored over a long period of time. As shown in the table above, 3.6 MMtCO₂/yr is estimated to be sequestered annually in wood products.⁸³ Additional details on the forest carbon inventory methods can be found in Annex 3 to the US EPA's 2006 GHG inventory for the US.⁸⁴

⁸² Rich Birdsey, USFS, personal communication with CCS, May 2007.

⁸³ Jim Smith, USFS, personal communication with S. Roe, CCS, October 2006.

⁸⁴ Annex 3 to EPA's 2006 report, which contains estimates for calendar year 2004, [http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR6MBLNO/\\$File/06_annex_Chapter3.pdf](http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR6MBLNO/$File/06_annex_Chapter3.pdf).

For the 1990 and 2000 historic emission estimates as well as the reference case projections, the forest area and carbon densities of forestlands were assumed to be at the same levels as those shown in the Table H1. Information is not currently available on the near term effects of climate change and their impacts on forest productivity. Hence, there is no change in the estimated future sinks for 2010 and 2020.

In order to provide a more comprehensive understanding of GHG sources/sinks from the forestry sector, the Center for Climate Strategies (CCS) also developed some rough estimates of state-wide emissions for methane (CH₄) and nitrous oxide (N₂O) from wildfires and prescribed burns. A study published earlier this year in *Science* indicated an increasing frequency of wildfire activity in the western US driven by a longer fire season and higher temperatures.⁸⁵

CCS used 2002 emissions data developed by the Western Regional Air Partnership (WRAP) to estimate CO₂e emissions for wildfires and prescribed burns.⁸⁶ 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 carbon dioxide emissions from fires are captured within the carbon pool accounting methods described above). The N₂O 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 wildfires and prescribed burns contributed about 0.24 MMtCO₂e of CH₄ and N₂O. About 90% of the CO₂e was contributed by CH₄. In 2002, there were about 172,000 acres burned by wildfires and prescribed burns in Idaho. Note that this 2002 level of wildfire activity compares to over 900,000 acres burned in Idaho in 1996.⁸⁷

A comparison estimate was made using emission factors from a 2001 global biomass burning study⁸⁸ and the total tons of biomass burned from the 2002 WRAP fires emissions inventory. This estimate is 0.29 MMtCO₂e with about equal contributions from CH₄ and N₂O on a CO₂e basis. Given the large swings in fire activity from year to year and the current lack of data for multiple years, CCS did not include these estimates in with the annual forestry flux estimates presented in the emissions summaries of this report. However, on the basis of total acres burned in 1996 and 2002, it appears that forest fires contribute on the order of 0.3 – 1.3 MMtCO₂e annually in Idaho from CH₄ and N₂O emissions.

Key Uncertainties

It is important to note that there were methodological differences in the two FIA cycles (used to calculate carbon pools and flux) that can produce different estimates of forested area and carbon

⁸⁵ Westerling, A.L. et al, "Warming and Earlier Spring Increases Western US Forest Wildfire Activity", *Scienceexpress*, July 6, 2006.

⁸⁶ *2002 Fire Emission Inventory for the WRAP Region Phase II*, prepared by Air Sciences, Inc. for the Western Regional Air Partnership, July 22, 2005.

⁸⁷ *1996 Fire Emission Inventory*, Draft Final Report, prepared by Air Sciences, Inc. for the Western Regional Air Partnership, December 2002.

⁸⁸ 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.

density. For example, the FIA program modified the definition of forest cover for the woodlands class of forestland. Earlier FIA cycles defined woodlands as having a tree cover of at least 10%, while the newer sampling methods used a woodlands definition of tree cover of at least 5% (leading to more area being defined as woodland). In woodland areas (low productivity forests such as pinyon-juniper), the earlier FIA surveys might not have inventoried trees of certain species or with certain tree form characteristics (leading to differences in both carbon density and forested acreage). Given that woodlands do not make up much of Idaho's forests, these methodological differences are not thought to have a substantial effect on the flux estimates.

Also, FIA surveys since 1999 include all dead trees on the plots, but data prior to that are variable in terms of these data. As shown in Table H1, the standing dead and down/dead pools contribute about 10% of the total estimated forest flux (excluding soil carbon from the estimated total flux). The modifications to FIA surveys are a result of an expanded focus in the FIA program, which historically was only concerned with timber resources, while more recent surveys have aimed at a more comprehensive gathering of forest biomass data. The effect of these changes in survey methods has not been estimated by the USFS. Western National Forests show a relatively large rate of carbon sequestration concurrent with an increase in forest area. It is possible that changes in FIA sampling resulted in more forest area coming into the inventory sample in the second time period.

As mentioned above, CCS included the forestry estimates without the soil carbon pool in the emissions summary tables (see Tables ES-1 and Table 1) for this report, since the USFS has indicated a high level of uncertainty for this carbon pool. These uncertainties are likely to remain until additional data from measurements and potentially improved modeling methods are developed. In Idaho, the soil carbon pool was estimated by USFS to sequester a small amount of carbon annually, and hence its removal does not have a large effect on the overall forest flux estimates.

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 Idaho. 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 Intergovernmental Panel on Climate Change (IPCC; see Appendix J for more information on BC and other aerosol species). Black carbon 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.⁸⁹ This appendix describes these data and methods for estimating mass emissions of BC and then transforming the mass emission estimates into carbon dioxide (CO₂) equivalents (CO_{2e}) in order to present the emissions within a greenhouse gas (GHG) context.

In addition to the PM inventory data from WRAP, PM speciation data from the United States Environmental Protection Agency's (US EPA) 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 ongoing work being conducted by E.H. Pechan & Associates, Inc. (Pechan) for the US EPA on updating the SPECIATE database.⁹⁰ These new profiles have just recently been released by EPA. As will be further described below, both BC and OM emission estimates are needed to assess the CO_{2e} of BC emissions. While BC and OM emissions data are available from the WRAP regional haze inventories, the Center for Climate Strategies (CCS) favored the newer speciation data available from the US 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 the US EPA for important BC emissions sources (e.g., most fossil fuel combustion sources).

After assembling the BC and OM emission estimates, the mass emission rates were transformed into their CO_{2e} 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 PM 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 US EPA's SPECIATE database as approved by US 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 CO_{2e} 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 II.

⁸⁹ Tom Moore, Western Regional Air Partnership, data files provided to Steve Roe, CCS, December 2006.

⁹⁰ Version 4.0 of the SPECIATE database and report is expected to be finalized during the Fall of 2006 and will be provided via EPA's web site (<http://www.epa.gov/ttn/chief/emch/speciation/index.html>).

Development of CO₂e for BC+OM Emissions

We used similar methods to those applied previously in Maine and Connecticut for converting BC mass emissions to CO₂e.⁹¹ These methods are based on the modeling of Jacobson (2002)⁹² and his updates to this work (Jacobson, 2005a).⁹³ Jacobson (2005a) estimated a range of 90:1 to 190:1 for the climate response effects of BC+OM emissions as compared to the amount of carbon in CO₂ 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 CO₂e 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 CO₂). Therefore, in order to express the BC emissions as CO₂e, 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 CO₂e factors of 330 and 697 to obtain a low and high estimate of CO₂e for each sector. An example calculation of the CO₂e emissions for 10 tons of PM less than 2.5 microns (PM_{2.5}) from onroad diesel exhaust follows:

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

$$\text{Low estimate CO}_2\text{e} = (6.13 \text{ tons BC}) (330 \text{ tons CO}_2\text{e/ton BC+OM}) (3 \text{ tons BC+OM/ton BC}) (0.907 \text{ metric ton/ton}) = 5,504 \text{ metric tons CO}_2\text{e}$$

$$\text{High estimate CO}_2\text{e} = (6.13 \text{ tons BC}) (697 \text{ tons CO}_2\text{e/ton BC+OM}) (3 \text{ tons BC+OM/ton BC}) (0.907 \text{ metric ton/ton}) = 11,626 \text{ metric tons CO}_2\text{e}$$

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).

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

⁹¹ 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.

⁹² 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.

⁹³ 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.

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 Idaho total about 3.2 MMtCO₂e in 2002. This is the mid-point of the estimated range of emissions. The estimated range is 2.1 – 4.4 MMtCO₂e (see Table I1). The primary contributing sectors in 2002 were nonroad diesel (73%), onroad diesel (14%), nonroad gasoline (6%), and rail (4%).

The nonroad diesel sector includes engine exhaust emissions used for construction/mining, commercial, industrial and agricultural purposes, and recreational vehicles. Agricultural engines contributed about 78% of the nonroad diesel total, while construction and mining engines contributed another 13%. For nonroad gasoline engines, primary contributors included recreational equipment (41%) and pleasure craft (35%).

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.

Based on 2018 projected emission estimates from the WRAP⁹⁴, there will be a drop in the future BC emissions for the onroad and nonoad diesel sectors due to new Federal engine and fuels standards that are currently being phased in to reduce PM emissions. For the nonroad diesel sector the estimated 2.4 MMtCO₂e in 2002 drops to 0.7 MMtCO₂e in 2018. For the onroad diesel sector, 0.5 MMtCO₂e was estimated for 2002 dropping to 0.07 MMtCO₂e in 2018. Emissions from the rail and nonroad gasoline sectors rose slightly in 2018 compared to 2002. No significant reductions are expected in the other emission sectors. The development of emission estimates for each of the smaller source sectors was beyond the scope of this analysis.

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).⁹⁵ There are also a number of other indirect radiative effects that have been modeled (see, for example, Jacobson, 2002, as noted in the footnotes on the previous pages).

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.

⁹⁴ Tom Moore, Western Regional Air Partnership, personal communication and data files provided to S. Roe, CCS, January 2007.

⁹⁵ IPCC, 2001. Climate Change 2001: The Scientific Basis, Intergovernmental Panel on Climate Change, 2001.

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.

Table 11. 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		
Electricity Generating Units (EGUs)	Coal	0	0	0	0	0	0.0%
	Oil	0	0	0	0	0	0.0%
	Gas	0	1	1	0	0	0.0%
	Other	0	0	0	0	0	0.0%
Non-EGU Fuel Combustion (Residential, Commercial, Industrial)							
	Coal	9	14	23	9,383	19,817	0.5%
	Oil	0	0	0	225	476	0.0%
	Gas	0	22	22	0	0	0.0%
	Other ^a	322	1,559	1,881	13,497	28,508	0.7%
Onroad Gasoline (Exhaust, Brake Wear, & Tire Wear)		54	214	269	20,780	43,891	1.0%
Onroad Diesel (Exhaust, Brake Wear, & Tire Wear)		326	138	464	290,659	613,906	14.0%
Aircraft		17	33	50	16,626	35,117	0.8%
Railroad ^b		83	27	110	81,784	172,737	3.9%
Other Energy Use	Nonroad Gas	134	378	512	132,786	280,460	6.4%
	Nonroad Diesel	1,521	499	2,020	1,505,809	3,180,451	72.7%
	Other Combustion ^c	0	0	0			0.0%
Industrial Processes		1	32	33	31	65	0.0%
Agriculture ^d		56	1,401	1,457	0	0	0.0%
Waste Management	Landfills	0	0	0	0	0	0.0%
	Incineration	0	0	0	0	0	0.0%
	Open Burning	295	3,791	4,086	0	0	0.0%
	Other	0	0	0	0	0	0.0%
Wildfires/Prescribed Burns		1,216	11,990	13,206	0	0	0.0%
Miscellaneous ^e		301	4,922	5,223	0	0	0.0%
Total		4,336	25,021	29,356	2,071,580	4,375,428	100%

^a Industrial wood combustion and large bore diesel internal combustion engines.

^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 inventories⁹⁶ 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).

⁹⁶ See FCCC/CP/1999/7 at www.unfccc.de

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 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 (SF₆)—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:

$$\text{Tg CO}_2 \text{ Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1,000 \text{ Gg}} \right) \text{ where,}$$

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.

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