Nevada Statewide Greenhouse Gas Emissions Inventory and Projections, 1990-2020

Nevada Division of Environmental Protection
Updated - December 2008

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ACRONYMS AND ABBREVIATIONS

AEO – Annual Energy Outlook
Ag – Agriculture
BLM – United States Bureau of Land Management
BOD – Biochemical Oxygen Demand
BTU – British thermal unit
$CaCO_3$ – Calcium Carbonate
CBM – Coal Bed Methane
CCS – Center for Climate Strategies
CFCs – Chlorofluorocarbons
CH_4 – Methane
CNG – Compressed Natural Gas
CO – Carbon Monoxide
CO_2 – Carbon Dioxide
CO_2e – Carbon Dioxide equivalent
CRP – Federal Conservation Reserve Program
DAQEM – Department of Air Quality and Environmental Management
DSM – Demand-Side Management
EEC – Ely Energy Center
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
GDP – Gross Domestic Product
GHG – Greenhouse Gases
GSP – Gross State Product
GWh – Gigawatt-hour
HFCs – Hydrofluorocarbons
HNO_3 – Nitric Acid
IPCC – Intergovernmental Panel on Climate Change
kWh – Kilowatt-hour
LF – Landfill
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)
MMcf – Million cubic feet
MMt – Million Metric tons
$MMtCO_2e$ – Million Metric tons Carbon Dioxide equivalent
MPO – Metropolitan Planning Organization
MSW – Municipal Solid Waste
MW – Megawatt

MWh – Megawatt-hour
N – Nitrogen
N_2O – Nitrous Oxide
NO_2 – Nitrogen Dioxide
NOx – Nitrogen Oxides
NAICS – North American Industry Classification System
NASS – National Agricultural Statistics Service
NDOT – Nevada Department of Transportation
NDEP – Nevada Division of Environmental Protection
NFC – Nitrogen Fixing Crops
ODS – Ozone-Depleting Substances
PFCs – Perfluorocarbons
PUCN – Public Utilities Commission of Nevada
PV – Photovoltaic
RCI – Residential, Commercial, and Industrial
RPS – Renewable Portfolio Standard
RTC – Regional Transportation Commission
SCR – Selective Catalytic Reduction
SEDS – State Energy Data System
SF_6 – Sulfur Hexafluoride
SIT – State Greenhouse Gas Inventory Tool
T&D – Transmission and Distribution
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
WAPA – Western Area Power Administration
WECC – Western Electricity Coordinating Council
WRAP – Western Regional Air Partnership
WW – Wastewater

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EXECUTIVE SUMMARY

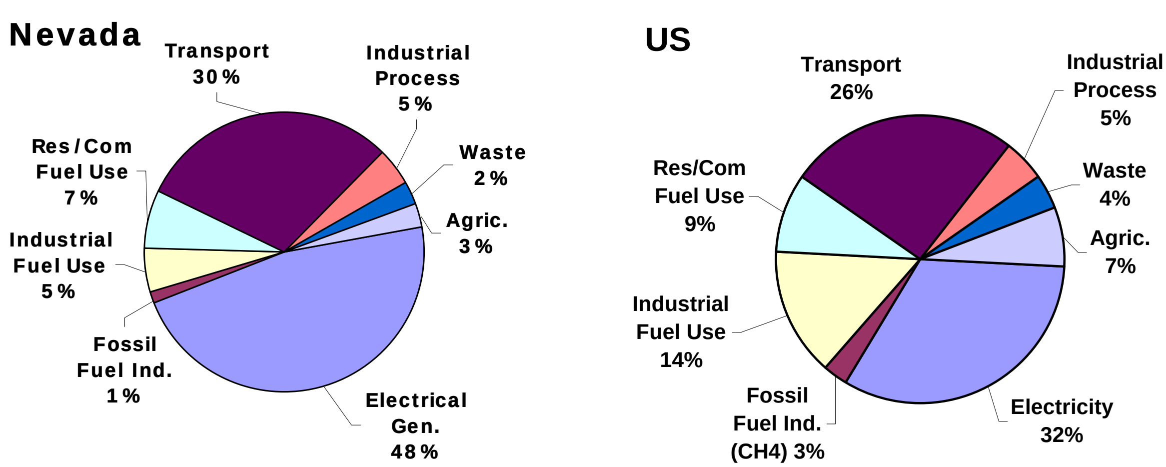
The summary presents a historical and projected State-wide GHG emissions inventory, including a comparison of Nevada's emissions to U.S. emissions, and observations concerning state GHG emission trends and estimation uncertainties. The section concludes with a summary table showing both historic and projected emissions estimates based on the contribution of each emissions sector.

Analysis of Nevada's GHG emissions indicate that for 2005, the most recent year of historical data, Nevada's statewide emissions totaled approximately 56.3 million metric tons of carbon-dioxide equivalent ($MMtCO_2e$) emissions, an amount approximately equal to 0.8% of total U.S. GHG emissions in that year.[1] CO_2 represented approximately 91% of Nevada's GHG emissions, with CH_4, N_2O, and HFCs/PFCs representing approximately 4%, 3%, and 2%, respectively. SF_6 emissions accounted for less than 0.5% of total emissions in 2005.

Together, the combustion of fossil fuels for electrical generation and transportation accounted for approximately 78% of Nevada's gross GHG emissions in 2005. Emissions in the residential, commercial and industrial sectors, most of which are associated with space and process heating, constituted approximately 12% of total emissions. Industrial process emissions (derived from non-combustion based emissions) comprised another 5% of emissions in 2005, and the emissions associated with agriculture, landfills and wastewater management facilities, and emissions from the fossil fuel industry together accounted for the remaining 6%.

Although the 2005 electrical generation and transportation sectors are the principal GHG emissions sources in Nevada and nationally (see Figure ES.1), electrical generation sector emissions in Nevada comprise a much higher percentage (48% to 32%) of total emissions than they do nationally. Nevada's transportation emissions also constitute a higher percentage than the national average (30% to 26%). These higher values are offset by lower emissions from Nevada's industrial fuel use and agriculture sectors.

Figure ES.1 Gross GHG Emissions by Sector in 2005, Nevada and U.S.



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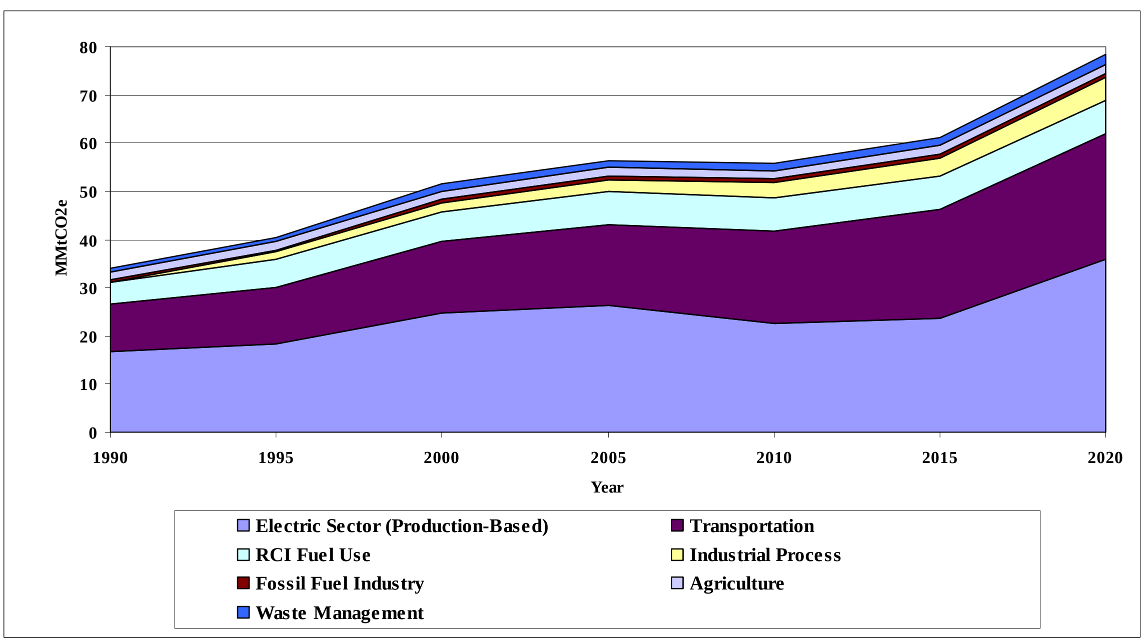
[1] United States emissions estimates are drawn from US EPA 2007. *Inventory of US Greenhouse gas Emissions and Sinks: 1990-2005*.

Trends in annual GHG emissions over the historic and projected emissions periods by source sector are shown in Figure ES.2. These emissions include all six GHGs (carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (HF_6)), in carbon dioxide equivalents. Between 1990-2005, Nevada's emissions grew from 34.1 MMtCO_2e to 56.3 MMtCO_2e, for an increase of approximately 65%, as compared to 16.3% growth in U.S. GHG emissions during the same period. The emissions increase was largely driven by Nevada's rapid population growth over the same period. Electricity generation and transportation were the two sectors responsible for the majority of the growth in GHG emissions during the last eighteen years.

GHG emissions are expected to increase at a more rapid rate during the projection period, to a total of 78.4 MMtCO_2e by 2020, due to increased electricity production; however, future trends in electrical generation are based on a variety of highly volatile factors. Changes to Nevada's generation infrastructure depend on factors ranging from the cost of new generation and construction, to potential costs of environmental regulations, to tightening credit markets. This uncertainty reduces the degree of confidence in forecasts of future electricity generation emissions. In order to better assess the potential range of emissions, seven different hypothetical scenarios were created and analyzed. The scenarios were selected to include a wide range of possible options: from the construction of no new coal-fired plants to multiple new coal-fired power plants, and include new natural gas plants and the retirement of older coal-fired units. The State-required integrated resource planning (IRP) analysis, used to ensure that future supplies of energy are adequate to meet consumer demand, was used as the base-line for all the projection scenarios and is included in Figure ES.2 and Table ES.1. The results for each of the other scenarios are presented in the Electricity Section. Emissions are expected to increase under all scenarios.

Figure ES.2 Trends in Annual Nevada Gross GHG Emissions by Sector, 1990-2020



A breakdown of net growth in emissions by sector shows that not only are transportation and electric generation the largest producers of GHG in the State, but they are also the sectors that are projected to experience the most future growth. Figure ES.3 shows the net growth in sector emissions, in $MMtCO_2e$/yr, during both the historic period (1990-2005) and the projection period (2005-2020). The historic bars (green) represent the net increase in emissions from 1990 to 2005, while the forecast bars (blue) represent the expected net gain from 2005 to 2020. The hatched bar represents the variation associated with the different projection scenarios evaluated for the electrical generation sector. Nevada contains two areas, forested lands and agricultural soils, which are estimated to be net sinks (sources of stored or sequestered carbon) for GHG emissions, accounting for approximately -5 $MMtCO_2e$/yr (these sequestration rates are assumed to remain constant over time and are not included in Figure ES.3).

Figure ES.3 Sector Contributions to Gross Emissions Growth in Nevada, 1990-2020: Historical Growth and Projections of Future Emissions

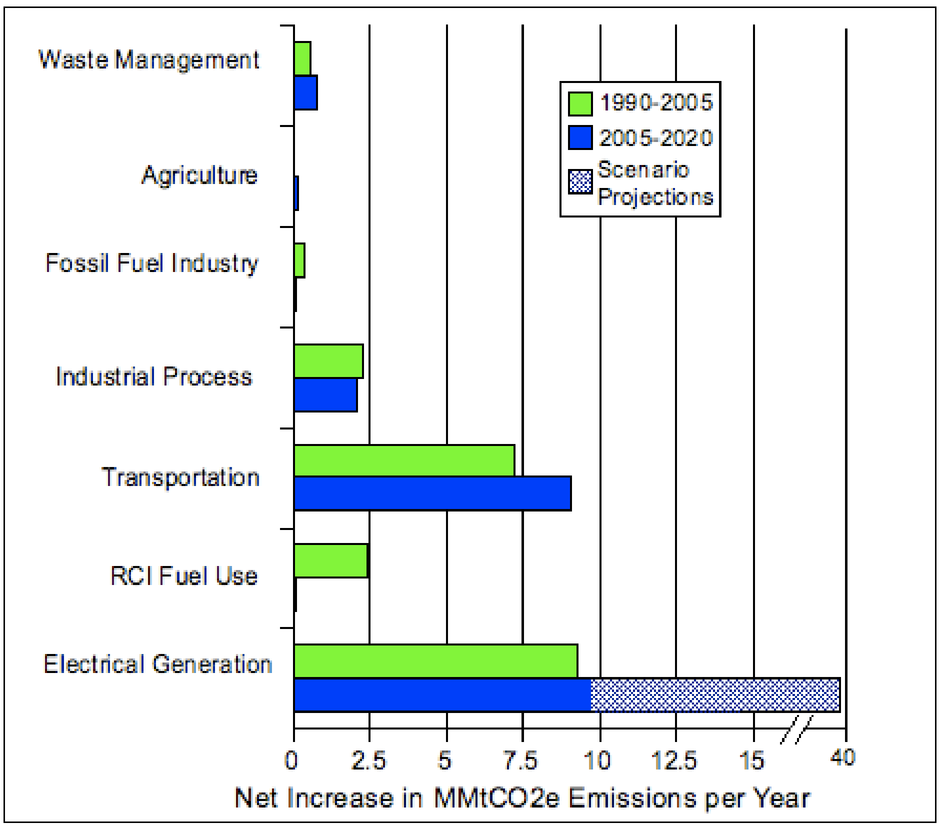


Table ES.1 Nevada Historical and Projected Reference Case Emissions ($MMtCO_2e$), by Sector[a]

Sector	1990	2000	2005	2010	2020
Electrical Generation (Production –based)	16.9	24.8	26.2	22.5	36.0
Coal	15.3	18.1	18.1	8.7	18.0
Natural Gas	1.3	6.6	8.1	13.8	18.0
Oil	0.26	0.06	0.02	0.03	0.03
Electrical Generation (Net-Consumption-Based)	12.7	20.0	22.5	22.0	27.9
Net Imported/Exported Electricity	6.0	6.5	10.1	2.3	0.0
Residential/Commercial/Industrial (RCI)	4.4	6.0	6.8	6.9	6.9
Coal	0.4	0.5	0.4	0.4	0.3
Natural Gas	2.2	3.6	4.3	4.4	4.6
Oil	1.9	1.8	2.1	2.0	1.9
Wood (CH_4 and N_2O)	0.02	0.03	0.02	0.02	0.02
Transportation	9.7	14.9	16.9	19.3	26.0
Motor Gasoline	5.8	8.4	9.8	10.8	14.1
Diesel	1.4	2.7	3.6	4.6	7.1
Natural Gas, LPG, other	0.04	0.06	0.09	0.1	0.2
Jet Fuel and Aviation Gasoline	2.5	3.8	3.4	3.7	4.6
Industrial Process	0.2	2.1	2.5	3.1	4.6
Cement Manufacture (CO_2)	0.0	0.2	0.2	0.3	0.4
Lime Manufacture (CO_2)	0.0	0.8	0.8	0.9	1.4
Limestone & Dolomite Use (CO_2)	0.00	0.04	0.03	0.04	0.06
Soda Ash (CO_2)	0.01	0.02	0.02	0.02	0.02
Nitric Acid Production (N_2O)	0.0	0.3	0.3	0.3	0.3
ODS Substitutes (HFC, PFC, and SF6)	0.002	0.5	1.0	1.5	2.5
Electric Power T & D (SF6)	0.2	0.1	0.1	0.1	0.1
Fossil Fuel Industry	0.4	0.6	0.8	0.9	0.9
Natural Gas Industry	0.4	0.6	0.8	0.9	0.9
Oil Industry	0.03	0.01	0.004	0.003	0.001
Agriculture	1.6	1.8	1.6	1.7	1.8
Enteric Fermentation	0.7	0.7	0.7	0.7	0.8
Manure Management	0.1	0.1	0.2	0.2	0.2
Agricultural Soils	0.8	0.9	0.8	0.8	0.8
Agricultural Residue Burning	0.0001	0.0001	0.0001	0.0001	0.0001
Waste Management	0.8	1.4	1.4	1.5	2.2
Solid Waste Management	0.7	1.2	1.1	1.2	1.7
Wastewater Management	0.1	0.2	0.3	0.3	0.4
Total Gross Emissions (100% in-state)	34.1	51.5	56.3	55.8	78.4
increase relative to 1990		51%	65%	64%	130%
Forestry (sink)	-4.8	-4.8	-4.8	-4.8	-4.8
Agricultural Soils (sink)	-0.2	-0.2	-0.2	-0.2	-0.2
Net Emissions (including sinks)	29.1	46.5	51.3	50.8	73.4
increase relative to 1990		60%	76%	75%	152%

[a] Totals may not equal exact sum of subtotals shown in this table due to independent rounding.

1.0 INTRODUCTION

1.1 OVERVIEW

During the 2007 Nevada Legislative Session, the legislature passed Senate Bill 422, which is now codified in Nevada Revised Statutes Chapter 445B.137 and 445B.380. NRS 445B.380 requires that a statewide greenhouse gas (GHG) inventory be prepared and issued, at least every four years beginning in 2008. It further stipulates that the report includes the origin, types and amounts of greenhouse gases emitted throughout the State, and all supporting analyses and documentation.

This report presents a comprehensive inventory of all GHG emissions associated with activities in Nevada. It includes all six GHGs covered by the US and other national inventories: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The different relative potentials to produce the greenhouse affect by gases other than carbon dioxide can be accounted for by converting the emission levels of those five gases into an equivalent amount of CO_2. Emissions of all these GHGs are presented using a common metric, CO_2-equivalent (CO_2e), which indicates the relative contribution of each gas to its global warming potential.

In most cases, historical emissions estimates were available from 1990 through 2005, with projections of future GHG emissions calculated to 2020 (here referred to as reference case projections[2]). The projections are based on a compilation of various existing projections of electricity generation, other stationary and mobile fuel uses, and non-energy GHG-emitting activities. Assumptions associated with the emissions sector projections are described in detail throughout the report.

The report is organized into chapters covering each of the economic sectors that produce GHGs, consistent with the spring 2007 GHG Inventory prepared for Nevada by the Center for Climate Strategies (CCS).[3] Emphasis was placed on updating the three most significant GHG emitting sectors in Nevada: electrical generation, transportation, and the combined residential, commercial and industrial (RCI) sectors. Together these three sectors comprise over 90% of total GHG emissions generated in the State. The electricity generation sector is perhaps the most dynamic sector due to the amount of new generation capacity currently being proposed. Since the remaining sectors represent a much smaller portion of the overall inventory, they were not updated substantially from what was presented in the 2007 CCS report.

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2 "Reference Case" is similar to the term "base year" used in criteria pollutant inventories. However, it also generally contains both a most current year estimate (e.g., 2005) as well as estimates for historical years (1990, etc.). Projections from this reference case are made to future years based on business-as-usual assumptions of future year source activity.

3 The Center for Climate Strategies, spring 2007, *Nevada Greenhouse Gas Inventory and Reference Case Projections, 1990-2020.*

1.2 APPROACH, DATA & GENERAL METHODOLOGY

The principal goal of the sector inventories and reference case projections is to provide a general understanding of Nevada's historical, current, and projected GHG emissions. In most cases, the approach followed was the same as that used by the United States Environmental Protection Agency (US EPA) in its national GHG emissions inventory and those suggested in its guidelines for States[4,5] for emissions accounting in historical inventories. These inventory guidelines were based on the guidelines developed by the Intergovernmental Panel on Climate Change, an international organization responsible for coordinating methods for national GHG inventories.[6] US EPA tools were used as a starting point for all inventories and projections. Initial estimates created by these EPA tools were augmented and/or revised as more accurate state- and local-level data became available. The key sources of emissions data are shown in Table 1.1. The table provides the descriptions of the data provided by each source and how each data set was used for creation of the inventory and projections. In gathering the data and in cases where data sources conflicted, the highest priority was placed on local and state data and analyses, followed by regional source data, with national data or simplified assumptions such as constant linear extrapolation of trends used as defaults where necessary.

To the extent possible, emissions that are caused by activities that occur within the state of Nevada were reported. However, in the electricity sector, in addition to the emissions that result from the electricity produced in Nevada, the emissions associated with the electricity consumed in Nevada, regardless of where they were produced, were also reported. In general, a consumption-based approach is used to evaluate the impact of potential demand mitigation strategies. For example, reuse, 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.

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4 US EPA, April 2008. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006.* http://www.epa.gov/climatechange/emissions/usinventoryreport.html

5 http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html

6 http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm

Table 1.1 Key Sources for Nevada Data, Inventory Methods, and Growth Rates

Source	Information provided	Use of Information in this Analysis
US EPA State Greenhouse Gas Inventory Tool (SIT)	US EPA SIT is a collection of linked spreadsheets designed to help users develop State GHG inventories. US EPA SIT contains default data for each State for most of the information required for an inventory. The SIT methods are based on the methods provided in the Volume 8 document series published by the Emissions Inventory Improvement Program (http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html).	Where not indicated otherwise, SIT is used to calculate emissions from residential/commercial/industrial fuel combustion, transportation, industrial processes, agriculture and forestry, and waste. SIT emission factors (CO_2, CH_4 and N_2O per BTU consumed) were used to calculate energy use emissions.
US DOE Energy Information Administration (EIA) State Energy Data System (SEDS)	EIA SEDS provides energy use data in each State, annually through calendar year 2005.	EIA SEDS is the source for most energy use data. However, the NDEP used more recent data for electricity and natural gas consumption (including natural gas for vehicle fuel) from EIA for years after 2005. Emission factors from US EPA SIT were used to calculate energy use emissions.
US DOE Energy Information Administration *Annual Energy Outlook 2008* (AEO2008)	EIA AEO2008 projects energy supply and demand for the U.S. from 2005 to 2030 based on reference case, "business as usual" conditions. Various energy consumption associated metrics are estimated on a regional basis. Nevada is included in the Mountain Census region (AZ, CO, ID, MT, NM, NV, UT, and WY).	EIA AEO2008 is used to project changes in per capita (residential) and per employee (commercial/industrial) energy consumption.
American Gas Association – *Gas Facts*	Natural gas transmission and distribution pipeline mileage.	Pipeline mileage from *Gas Facts* used with SIT 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 are used to estimate annual disposal rate, which was used with SIT to estimate emissions from solid waste.
US Forest Service	Data on forest carbon stocks for multiple years.	Data are used to calculate carbon dioxide flux over time (terrestrial CO_2 sequestration in forested areas)
USDA National Agricultural Statistics Service (NASS)	USDA NASS provides data on crops and livestock.	Crop production data are used to estimate agricultural residue and agricultural soils emissions; livestock population data are used to estimate manure and enteric fermentation emissions

2.0 ELECTRICAL GENERATION SECTOR EMISSIONS

2.1 OVERVIEW

The electrical generation sector represents the largest source of GHG emissions in the state, accounting for approximately 46.6% of emissions produced in the state in 2005, the most recent year for which multi-sector historical emissions data was available. Sector emissions occur as a result of the combustion of fossil fuel at electrical generating facilities located both in and outside of the state. Carbon dioxide (CO_2) represented more than 99.5% of total sector emissions, with methane (CH_4) and nitrous oxide (N_2O) CO_2-equivalent emissions comprising the balance.

The electrical generation sector emissions are estimated in two ways. The first is an accounting of *production-based* emissions, i.e. the GHG emissions from power plants located in Nevada. The second estimation method is the accounting of *consumption-based* emissions, referring instead to the quantity of emissions related to the electricity actually consumed in Nevada, regardless of whether generated in the state or imported. Consumption-based emissions accounting can be used to track the influence of factors such as price changes in the cost of energy and/or the effectiveness of consumer programs designed to reduce electricity consumption.

The inventory of historic sector GHG emissions (1990-2006) indicates that coal-fired electricity generation was the predominant source of emissions through the end of 2005. During the historical period, this sector's emissions continued to increase through 2005 from 16.9 $MMtCO_2e$ in 1990 to 26.2 $MMtCO_2e$ by the end of 2005. These increases were due primarily to increases in natural gas-fired generation. For 2006, with the temporary closure of Nevada's largest coal-fired power plant, the Mohave Generating Station, Nevada's GHG emissions from the electricity sector decreased by approximately 36%, reducing total state-wide GHG emissions by 16.7%. Primarily as a result of the increase in natural gas-fired generation, and further affected by the shut down of Mohave, the carbon intensity of Nevada's electricity generation showed an unusually steep decline during this period. Generation carbon intensity is defined as the pounds of carbon dioxide equivalent emitted per megawatt-hour of electricity generated ($lbsCO_2e/MWh$). Carbon intensity dropped approximately 39% from an estimated 1,854 $lbsCO_2e/MWh$ in 1990 to 1,135 $lbsCO_2e/MWh$ by the end of 2006.

Not all of the electrical power used in Nevada is generated within the State. Nevada is currently a net importer of electricity, with approximately 30% of the total power consumed coming from generation outside of the state. Prior to 2000, the State of Nevada energy policy promoted a 50/50 power mix of generation to imports. Since 2000, the PUCN is promoting an 80/20 power mix. This shift toward energy independence has the potential to significantly impact overall emission of greenhouse gases and Nevada's carbon intensity.

There are a number of significant changes to the current electricity generation infrastructure that have been proposed, including a number of new facilities, modifications to existing facilities, and retirements of existing units and power plants. This uncertainty makes it difficult to forecast, with a high degree of confidence, future production-based emissions (those related only to electricity produced in Nevada, regardless of where it is consumed). It is equally difficult to forecast net-consumption-based sector emissions (those related to in-state and imported electricity that is consumed in Nevada) because in addition to the potential changes in in-state electricity generation infrastructure, the many sources of out-of-state electrical power are difficult to track and predict as well. The determination of which plants are constructed will likely be influenced by many factors as documented by the Nevada Public Utilities Commission (PUCN).[7] These uncertainties include economic factors such as the cost of new generation, cost of new construction, generation fuel costs, potential costs of environmental regulations, and tightening credit markets.

In order to better assess the full scope of potential future emissions resulting from proposed changes to Nevada's electrical generation infrastructure, seven hypothetical emission scenarios were analyzed. Each of these GHG emissions scenarios project that total electrical generation sector emissions will continue to increase. The specific amount will largely depend upon the amount of added generation capacity, fuel type, and capacity factor. As an example, emission Scenario 1 (refer to Table 2.3) was based on state-required integrated resource planning (IRP) analysis used to ensure that future supplies of energy are adequate to meet consumer demand. The IRP analysis was used for Scenario 1 because it provided a logical foundation upon which to project future emissions based upon future electricity generation requirements. Total estimated production-based emissions under Scenario 1 are projected to increase from 16.2 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) in 2006 to 36.0 $MMtCO_2e$ in 2020; an increase of nearly 122%. When viewed from the perspective of consumption-based emissions, Scenario 1 results in a projected increase of 23% from 22.7 $MMtCO_2e$ in 2006 to 27.9 $MMtCO_2e$ in 2020.

The remaining six scenarios represent different combinations of added coal-fired electrical generation plants, generation unit retirements, and the restart of the Mohave Generating Station with natural gas-fired generation units. The projected increased production-based GHG emissions range from an increase of 37.3 $MMtCO_2e$ by 2020 if all proposed coal-fired projects are built (a 230% increase from 2006 levels using Scenario 4) to an increase of 10.5 $MMtCO_2e$ by 2020 if no new coal fired plants are constructed, combined with the continued operation of the Reid Gardner units 1, 2, and 3 (a 65% increase using Scenario 5).

Consumption-based emissions are also expected to increase under all scenarios; however, as expected the increases are less dramatic than those projected using a production-based approach. These emission increases during the period 2006 to 2020 range from 40% under Scenario 4 to only 8% using Scenario 5. It is expected that compliance with Nevada's renewable portfolio standard (RPS), which will increase the amount of electricity generated from renewable energy resources and lead to further implementation of energy efficiency and conservation measures, will in turn reduce total electrical generation emissions by approximately three $MMtCO_2e$ by the year 2020.

Finally, the carbon intensity (GHG emissions per megawatt-hour of electrical generation) of Nevada's electrical generation has steadily decreased since 1990. This is due primarily to the marked increase in natural gas-fired generation, along with the temporary closure of the coal-fired Mohave Generating Station at the end of 2005 – an event that resulted in an uncharacteristically large and potentially unsustainable reduction in carbon intensity. While measures implemented by the power industry to meet RPS requirements are expected to assist in lowering Nevada's carbon intensity, that number is expected to continue to change due to a

[7] Order issued in NPC and SPPC IRP action plan filings, docket numbers 08-05014 and 08-05015, p. 46 (http://pucweb1.state.nv.us/pucn/DktInfo.aspx?Util=Electric).

number of factors such as population growth, the fuel portfolio and the shift in the energy policy to promote more power independence.

2.2 METHODOLOGY

2.2.1 Estimation of Historic Emissions

Historical sector emissions were calculated using fossil fuel consumption data, for the period of 1990-2006, available through the EIA. Electrical generation emissions for this period were estimated using the methods provided in the U.S. EPA's Emissions Inventory Improvement Program (EIIP) guidance document for this sector as referenced in Table 1.1 of Section 1 of this report. Estimated CO_2 emissions from fossil fuel combustion were calculated by multiplying energy consumption by carbon content coefficients for each fuel. These quantities were then multiplied by the combustion efficiency (i.e. the fuel-specific percentage of carbon oxidized during combustion). The resulting fuel emission values, in pounds of carbon, were then converted to million metric tons of carbon equivalent ($MMtCO_2e$).

The general formula used for converting sector energy consumption to $MMtCO_2e$ is as follows:

$$BillionBtuConsumed * EmissionFactor(lbsC / MillionBtu) * CombustionEfficiency(\%) = Emssions(shorttonscarbon)$$

$$Emissions(shorttonscarbon) * 0.9072 * 1/1000000 = MMtCO2e$$

<u>Equation Legend:</u>
Billion Btu consumed refers to the total heat content of the applicable fuel
Emission factor refers to the conversion factor used to convert total heat content of the quantity of fuel consumed to pounds of carbon
Combustion efficiency refers to the percentage completeness of the combustion of the applicable fuel
0.9072 is a constant used to convert from short tons to metric tons.

Three additional data sources were used in developing the historic inventory of electrical sector emissions. Data available through the U.S. EPA's Clean Air Markets Database (CAMD) were used to compare the CO_2 emissions from individual power plants over 25 MW in generation capacity. Data from the State Energy Data Tables in the EIA's *Electric Power Annual* (2006), an annual report of the electricity industry, provided electricity generation and associated GHG emissions from Nevada power plants through 2006. Data concerning statewide historic and projected electricity sales forecasts were provided by the Public Utilities Commission of Nevada (PUCN). The electricity sales data were used to estimate emissions related to electricity exports and imports.

The methodology and data sources used to estimate the historic inventory of electrical sector emissions is essentially the same as that used by CCS in the development of its 2007 *Nevada Greenhouse Gas Inventory and Reference Case Projections, 1990-2020* baseline report. Any differences in this report are attributable to the use of corrected and/or updated energy consumption data subsequently released by the EIA, and the use of modified emission factors incorporated into the 2007 update to the EPA's SIT emissions estimation software tool.

2.2.2 Estimation of Projected Production-Based Emissions

The estimation of projected emissions for the period of 2007-2020 was based on the fuel type and capacity of electrical generating plants proposed for construction during the projection period. These include all coal and natural gas fired plants proposed by NV Energy (formerly known as Nevada Power and Sierra Pacific Power companies, prior to their Fall, 2008 merger), the two coal-fired independent power plants known as the White Pine Energy Station and the Toquop Energy Project, and the possible restart of the Mohave Generating Station fired only by natural gas. The emissions analysis was based on data provided by plant developers for plants currently undergoing air quality permitting, as well as proposed generation capacity additions as taken directly from NV Energy's generation plant planning documents.

These planning documents were submitted to the Nevada Public Utilities Commission (PUCN) in compliance with Nevada's utility integrated resource planning requirements. Planning information used for making emissions projections is contained in the loads and resources tables (low load forecast) included in Nevada Power Company's eighth amendment to the action plan of its 2007-2026 integrated resource plan (IRP), and Sierra Pacific Power Company's third amendment to its 2008-2027 IRP. As Nevada's IRP requirements necessitate the use of sophisticated economic modeling to forecast future in-state electricity demand, reliance on Nevada's IRP process supports a more reliable estimate of sector emission projections than the estimate based upon regional projections that were used in the 2007 CCS baseline report. A further benefit of this approach is that it allows for consideration of GHG emissions reductions associated with planned generation plant retirement.

The key assumptions used in the emissions estimation analysis are summarized in Table 2.1. These include the forecasted increase in electricity sales, the percentage of transmission and distribution system losses, the percentages of renewable energy and energy efficiency/conservation implemented as a result of RPS phase-in, and the mix of non-renewable generation plants constructed. The table also includes assumed plant heat rate, which is a measure of the efficiency of a generation plant, and assumptions regarding future operation of existing generation facilities.

Table 2.1 Key Assumptions for Estimating Projected Electrical Generation Emissions

Electricity sales	Average annual growth of 1.5% from 2007 to 2020, based on growth rates provided by the Public Utilities Commission of Nevada.
Transmission and Distribution (T&D) losses	For the period of 1990-2000, losses of 10% of generation amount are assumed, based on the average of statewide losses, 1994-2000, (data from the US EPA Emission & Generation Resource Integrated Database[8]); however, data provided directly from NV Energy states T&D losses on NV Energy's southern Nevada and northern Nevada systems in 2006 were 5.4% and 4.8%, respectively.[9] Therefore it is possible that the 10% loss factor may be too liberal and thus overestimate emissions associated with electricity imports or exports.
New Renewable Generation Sources	Nevada's renewable portfolio standard (RPS) will be met by NV Energy and other providers of electric service (representing a combined 87% of statewide electricity sales in 2006) as follows: 12% of the covered sales will be met by renewable generation by the end of 2009, increasing to 20% by 2015 and in subsequent years. New resources added to meet the RPS are assumed to be 5% solar, 25% demand-side management and the remainder met by a split between new geothermal and wind.
New Non-Renewable Generation Sources (2009-2010)	The mix of new non-renewable generation is based on plants under construction for this period (detailed in Table 2.2).
New Non-Renewable Generation Sources (2011-2020)	The mix of new generation in this period is based on the IRP reference case and six alternative scenarios as detailed in Table 2.3.
Heat Rates	In most cases, plant heat rate information was obtained from FERC's Form 1 report, EPA's eGRID, and directly from developers of proposed plants. Where the information was not available NDEP assumed, based upon prior research by the CCS, heat rates for new gas and coal generation will be 7000 Btu/kWh and 9000 Btu/kWh, respectively.
Operation of Existing Facilities	Existing non-hydro facilities are assumed to continue to operate as they did in 2006. Existing hydro facilities are assumed to generate 2,292 GWh per year, the average generation over the period 1997-2006.

[8] http://www.epa.gov/cleanenergy/egrid/index.htm

[9] Sierra Pacific Resources, March 2008. GHG emissions inventory report to the California Climate Action Registry for calendar year 2006.

Table 2.2 presents a listing of all coal and natural gas fired generation plants or electric generating units (EGUs) that have been temporarily shutdown, retired, scheduled for retirement, placed into service or proposed for construction during the period of 2005-2020. Included in the table is the estimated GHG emissions and carbon intensity associated with each plant or EGU. The list was generated based upon the review of power plants or EGUs currently in the construction permitting stage, those planned for future construction, and those units that are expected to be retired.

In addition to the merchant plants in the construction permitting stage (White Pine Energy Station and Toquop Energy Project), the list includes all NV Energy plants currently in the construction permitting stage, planned for future construction and planned for retirement as stated in its integrated resource plan documents. The estimated emissions associated with each plant or EGU in the list was added to the total of electrical generation sector emissions as of 2006 to obtain the total electrical sector emissions for each year of the projection period. Projected emissions, starting in 2007, include the emissions associated with the first full year of operation of the Chuck Lenzie plant and Harry Allen unit 4, both placed into service in 2006, and exclude annual emissions associated with the retirement of Clark generation units 1-3 in 2006.

Table 2.2 Changes in Major Fossil-Fuel Power Plant/EGU Generation Capacity, 2005-2020

	Plant Name	Fuel	Status	Megawatts of Generating Capacity	Expected Annual Generation	Expected Annual Emissions	Expected Annual Carbon Intensity	Plant Ownership / Notes
					GWh	MMtCO2e	lbsCO2/MWh	
Temporary Shutdown	Mohave	Coal	temporarily shutdown at end of 2005	-1580	-9,399	-9.4	2,210.3	Southern California Edison (primary owner) / Generation and emission estimates are average levels 2000-2005 (EPA Clean Air Markets Data)
Retired EGUs	Clark Units 1-3	natural gas	retired 2006	-190	-801	-0.5		NV Energy / Based on 2002 (highest) production
EGUs Scheduled for Retirement	Clark Station Unit 4	natural gas	by 12/31/2010	-59	-41	0.0	818.0	NV Energy
	Tracy Unit 1	natural gas	by 12/31/2013	-53	-137	-0.1	818.0	NV Energy
	Tracy Unit 2	natural gas	by 12/31/2015	-83	-214	-0.1	818.0	NV Energy
	Reid Gardner Units 1-3	coal	by 12/31/2016	-300	-1,777	-1.5	1,854.6	NV Energy
	Sunrise Unit 1	natural gas	by12/31/2016	-80	-60	0.0	818.0	NV Energy
	Ft. Churchill Unit 1	natural gas	by 12/31/2018	-113	-466	-0.2	818.0	NV Energy
New Plants & EGUs Recently Placed Into Service	Western 102	natural gas	in service 2005	116	406	0.2	1,022.5	Barrick Goldstrike Mines
	Chuck Lenzie CCGT	natural gas	in service 2006	1220	6,829	2.5	818.0	NV Energy
	Harry Allen Unit 4	natural gas	in service 2006	76	42	0.0	1,484.3	NV Energy
	Tracy CCGT	natural gas	in service June, 2008	541	3,554	1.3	818.0	NV Energy
	TS Power Plant	coal	in service June, 2008	205	1,526	1.4	2,050.9	Newmont Nevada Energy Investment, LLC
	Clark GT Peaking Units 1 & 2	natural gas	in service 2008 (various dates)	619	813	0.3	818.0	NV Energy
Proposed Plants & EGUs	Harry Allen CCGT Units 5 & 6	natural gas	planned for June, 2011	484	3,180	1.2	818.0	NV Energy
	Mohave Units 1 & 2	natural gas, baseload	2012 ?	1580	9,399	5.0	1,165.6	Owner TBD
	White Pine Energy Station	coal (pulverized)	planned for mid-2013	1590	11,839	10.7	1,996.2	White Pine Energy Associates, LLC
	Toquop Energy Project	coal (pulverized)	planned for mid-2013	750	5,585	5.0	1,958.1	Toquop Energy, LLC
	Ely Energy Center Plase I	coal (pulverized)	unit 1 planned for mid-2015, #2 in mid-2016	1500	11,169	9.6	1,892.9	NV Energy
	unnamed CT #16	natural gas	planned for 2016	225	296	0.1	818.0	NV Energy
	unnamed CC #18	natural gas	planned for 2018	544	3,574	1.3	818.0	NV Energy
	unnamed CC #19	natural gas	planned for 2019	541	3,554	1.3	818.0	NV Energy
	Ely Energy Center Phase II	coal gasification	date unknown	1000	7,446	unknown	unknown	NV Energy

Sources: IRP documents filed with PUCN and personal communication with non-utility owned coal plant developers. Data used for emission estimates of existing and proposed plants taken from EPA's Clean Air Markets Database (Mohave – coal firing only), FERC Form #1 (existing utility-owned plants), eGRID (non-utility), personal communication (plants proposed by non-utility entities), and ENSR Corporation's *BART Determination for the Mohave Generating Station: Natural Gas Firing Options*.
Generation Assumptions: Proposed plant capacity factors are assumed to be 0.15 for peaking plants, 0.50 for intermediate-sized simple cycle natural gas plants, 0.75 for large combined cycle (CC) natural gas plants, and 0.85 for baseload coal plants. Megawatt capacity figures for existing utility plants taken from SPR's report of 2006 GHG emissions submitted to the California Climate Action Registry (CCAR).

Given the variety of proposed plants and EGUs listed in Table 2.2, seven plausible alternative emissions scenarios were analyzed using the planning criteria included in the IRP documents filed with the PUCN. The projection scenarios are described in detail in Table 2.3. Scenario 1 includes the planned addition of Phase I of the proposed Ely Energy Center and the retirement of Reid Gardner Units 1, 2, and 3. Scenario 2 projects the addition of the White Pine Coal facility planned by LS Power.

The addition of the Toquop Coal plant is analyzed in Scenario 3. Scenarios 4 and 5 represent the potential that all proposed coal-fired plants would be built, or that none of them would be built, respectively. The final two scenarios, 6 and 7, depict the restart of the Mohave plant with natural gas-fired generation units. Scenario 6 includes no new coal generation while scenario 7 adds a 1500 MW coal-fired plant.

Each scenario includes the emissions reductions achieved through the required phase-in of the Nevada renewable portfolio standard (RPS). This includes electricity sales that can be supplied by renewable energy, and electricity demand that is lowered in response to demand-side management (DSM) programs.

Reduced emissions resulting from the RPS phase-in were estimated as the emissions that would otherwise be emitted from a natural gas fired combustion turbine (CT) used to produce an equivalent number of megawatt-hours. NV Energy uses CTs to meet daily fluctuation in consumer demand and to complement the intermittent availability of renewable energy sources such as solar and wind. This is due to their efficiency advantage associated with the utility's ability to quickly add or shut down relatively small increments of generation capacity as needed. Therefore emissions reductions based on avoided CT operation provides a rational basis for estimating emission reductions associated with electricity supplied from renewable energy sources and electricity demand reduced through energy efficiency and conservation.

The projection scenarios are described in Table 2.3.

Table 2.3 Future Electrical Generation Emissions Scenario, 2005-2020

Scenario	Descriptor	Explanation
1	**IRP Reference Case**	This scenario is based on NV Energy's proposed generation plant additions and retirements included in table 2.2, including Phase I of the Ely Energy Center (EEC) and the retirement of the coal-fired Reid Gardner units 1-3. Construction of the other proposed coal fired power plants and restart of the Mohave plant are not included in this scenario. The scenario does not consider the construction of Phase II of the Ely Energy Center as the date of construction of this facility is unknown.
2	**White Pine Coal**	This scenario is the same as scenario 1 except the EEC is replaced by the White Pine Energy Station and Reid Gardner units 1-3 are not retired.
3	**Toquop Coal**	This scenario is the same as scenario 1 except that the EEC is replaced by the Toquop Energy Project and Reid Gardner units 1-3 are not retired.
4	**All New Coal**	This scenario includes the projected emissions under scenario 1 as well as the emissions generated by the White Pine and Toquop coal plants.
5	**No New Coal**	This scenario includes the projected emissions of scenario 1 without the construction of any of the three proposed coal plants and non-retirement of Reid Gardner units 1-3.
6	**Mohave Restart as Natural Gas Only**	This scenario projects the same emissions as scenario 1 except that no new coal fired generation is added, Reid Gardner units 1-3 are not retired, and the Mohave plant is restarted and operated only on natural gas starting in the time period of 2011-2015.
7	**Mohave and 1500 MW of New Coal**	This scenario is the same as scenario 6 with the addition of one new coal plant of 1500 MW capacity in 2015.

2.2.3 Estimation of Projected Net-Consumption-Based Emissions

Nevada is part of the interconnected region managed by the Western Electricity Coordinating Council (WECC), an entity responsible for the coordination and promotion of electric system reliability. Due to this interconnection, electricity generated in Nevada can be exported to serve needs in other states and, conversely, electricity used in Nevada can be generated and imported from plants outside the state.

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. Consideration of only production-based emissions, discussed previously, does not account for GHG emissions from electricity consumed in Nevada but generated outside of the state.

In order to fully account for the emissions associated with electricity imports, one alternative approach is to account for *consumption-based or load-based* GHG emissions. The difficulty with this approach is properly accounting for the emissions from both imports and exports. Since the electricity flowing into or out of Nevada is a mix of all plants generating on the interconnected grid, it is impossible to physically track the sources of the electrons.

The approach used is a simplification of the consumption-based approach mentioned above. This approach, termed *net-consumption-based* accounting, estimates consumption-based emissions as the total of in-state (production-based) emissions after first deducting the emissions associated with electricity generated in Nevada and exported to serve the needs of utility customers outside the state, and then adding the emissions associated with the amount of imported electricity needed to equal Nevada's annual electricity consumption.[10]

Emissions for net imports (total imports minus exports) are calculated as the net amount of imported electricity multiplied by regional CO_2, CH_4 and N_2O emission rates and converted to $MMtCO_2e$. WECC sub-region electricity mix emission rates, listed in U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID2007), were used as the basis for calculation of net-consumption-based emissions. Of the three WECC sub-regions in which NV Energy and other Nevada power plant owners operate, the WECC Southwest sub-region (AZ/NM/SNV) has the highest CO_2e output rate per MWh of generation.[11] This rate was selected since the AZ/NM/SNV is the sub-region in which NV Energy plans to import the bulk of electricity acquired through purchased power agreements to meet its future customer needs.[12]

A rate of 1,332.6 $lbsCO_2e/MWh$ was then calculated by excluding the generation and emissions from the Nevada Power Company power control area (PCA)[13] and was used to calculate projected net-consumption-based emissions under each of seven alternative emission scenarios referenced in the discussion of methodology used to estimate production-based emissions.

2.3 RESULTS

2.3.1 Electricity Consumption

At approximately 13,492 kWh/capita/year (2005 data), Nevada's electricity use per person is higher than the typical U.S. per capita consumption of 12,879 kWh per year.[14] Historical data shows Nevada's per capita consumption[15] has been in the mid-range for states in the western region of the U.S. Many factors influence a state's per capita electricity consumption including the impact of climate on demand for cooling and heating, the size and type of industries in the

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10 eGRID and the Clean Market Database data were used to estimate net-based-consumption emissions. It was assumed that 100% of the electricity generated by the Apex, Bighorn and El Dorado Energy plants was exported out of the state along with 86%, 50%, and 29.9% of generation from the Mohave, Valmy and Reid Gardner (unit 4) plants, respectively, on the basis of plant ownership by non-Nevada utility entities. A source of data that would provide definitive accounting for the disposition of electricity generated at these six plants could not be identified. Starting in 2009, 100% of the Bighorn plant's generation was assumed to be used for in-state consumption consistent with the plant's purchase by NV Energy in October of 2008.

11 eGRID2007, file #7 of the aggregated Excel files.

12 Order issued in NPC and SPPC IRP action plan filings, docket numbers 08-05014 and 08-05015. (http://pucweb1.state.nv.us/pucn/DktInfo.aspx?Util=Electric)

13 eGRID2007, file #6 of the aggregated Excel files.

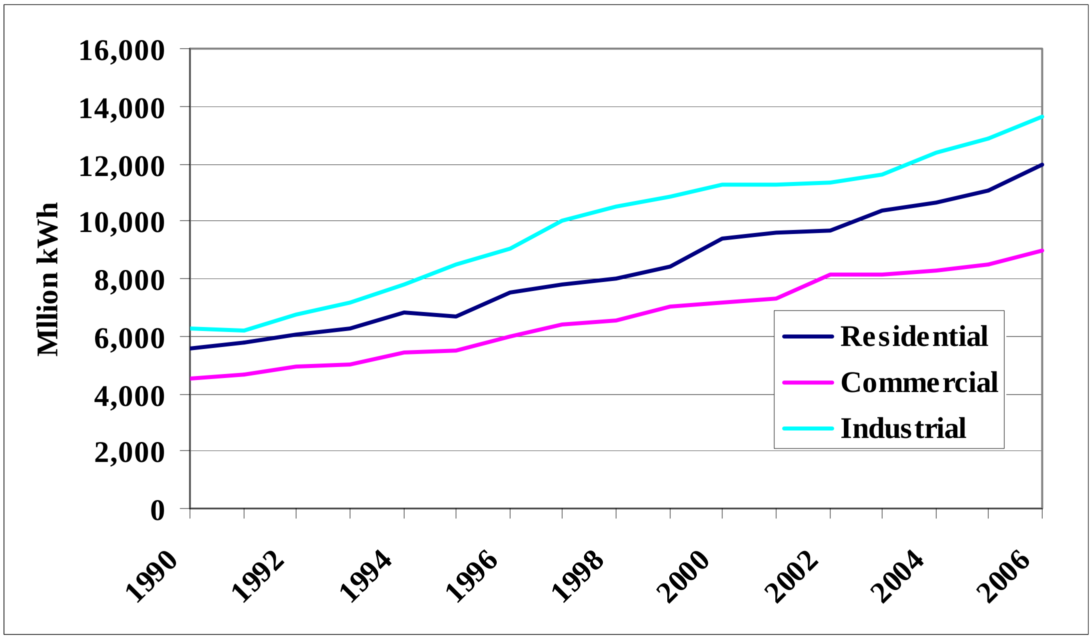
14 Calculated using U.S. Census Bureau population data and EIA electricity consumption data.

15 http://www.nwcouncil.org/energy/powerplan/5/Appendix%20A%20(Demand%20Forecast.pdf, p. A-34.

State, and the type and efficiency of electrical equipment and appliances used in the residential, commercial and industrial sectors.

As shown in Figure 2.1, electricity sales in Nevada have increased steadily from 1990 through 2006. Overall, total electricity consumption increased at an average annual rate of 4.8 percent from 1990 to 2006. During this period, residential sector electricity use grew by an average of 4.9 percent per year, the commercial sector by 4.3 percent per year, and the industrial sector by 5.0 percent per year.

Figure 2.1 Electricity Consumption by Sector in Nevada, 1990-2006



Source: EIA State Energy Data (1990-2005) and EIA Electric Power Annual State Data Tables 2006

Table 2.4 shows both historic and projected electricity consumption growth rates between 1990 and 2020. Projections for electricity sales from 2007 through 2017 were taken directly from the PUCN's internal, preliminary 2008 Nevada energy forecast summary.[16] Electricity sales projections for 2018 through 2020 were extended using the annual average growth rate from the PUCN forecast. The table indicates that the average annual growth in electricity sales during the projection period will be lower than during the historical consumption period. The PUCN's forecast includes the results of sophisticated econometric modeling of consumer electricity demand forecast by the University of Nevada Las Vegas Center for Business & Economic Research (CBER) and included in NV Energy's integrated resource planning documents. The lower rate of growth in consumer electricity demand should result in a reduction in the amount of additional electricity generation and GHG emissions than would occur under the historical rate of consumption growth.

16 PUCN, Nevada Energy Forecast Summary (internal, preliminary spreadsheet document prepared by Howard Hirsch), August 22, 2008.

Table 2.4 Annual Electricity Sales Growth Rates, Historic and Projected

	Historic 1990 - 2006	Projections 2007 - 2020
Residential	4.8%	2.2%
Commercial	4.2%	1.2%
Industrial	4.7%	1.1%
Total	**4.6%**	**1.5%**

Source: Historic from EIA SEDS data, projections from Public Utilities Commission of Nevada.

2.3.2 Electrical Generation

Historic Generation and Production-Based Emissions

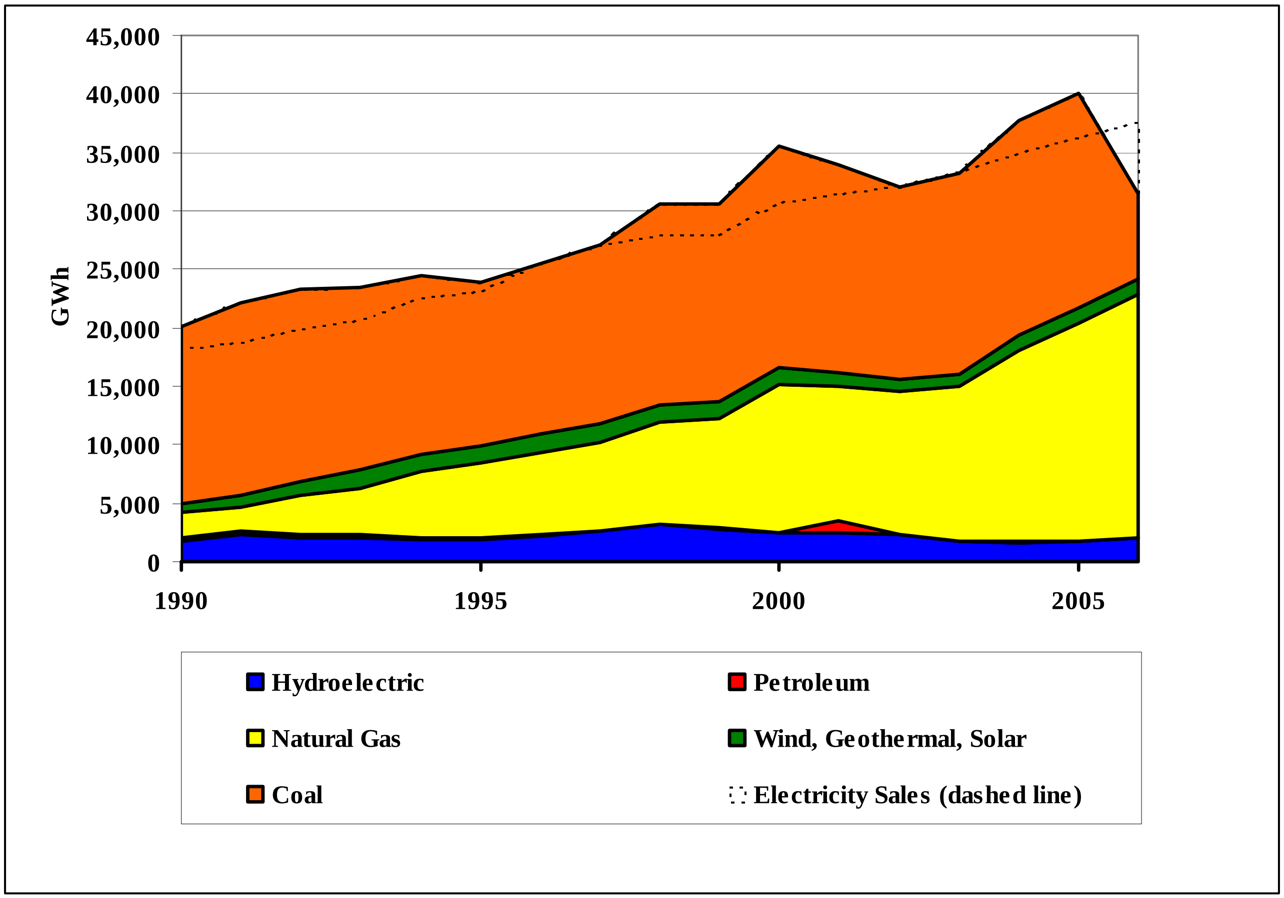
Coal and natural gas are the two largest sources of electrical generation in Nevada. Coal generation increased from 15,053 GWh in 1990 to 18,384 GWh in 2005. Emissions dropped dramatically to 7,254 GWh in 2006 due to the temporary shutdown of the Mohave Generating Station. However, during the same period, natural gas increased by an order of magnitude, from 2,217 GWh to 20,828 GWh. Historical trends in gigawatt-hours of electricity generation from 1990-2006 are displayed in Table 2.5 and Figure 2.2.

Table 2.5 GWh of Electricity Generation by Energy Source, 1990-2006

Generation Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Coal	15,053	16,366	16,443	15,628	15,325	13,972	14,657	15,251	17,161	16,908	18,932	17,737	16,413	17,086	18,257	18,384	7,254
Hydroelectric	1,735	2,365	1,986	1,972	1,876	1,942	2,164	2,587	3,166	2,828	2,429	2,514	2,268	1,757	1,615	1,702	2,058
Natural Gas	2,217	2,095	3,392	4,033	5,630	6,444	7,083	7,558	8,691	9,347	12,667	11,514	12,211	13,253	16,386	18,731	20,828
Petroleum	284	242	328	327	168	27	96	32	52	35	65	912	25	17	96	21	17
Wind, Geo, Solar	761	995	1,178	1,540	1,495	1,554	1,555	1,596	1,537	1,415	1,371	1,200	1,127	1,066	1,298	1,263	1,344
Total	20,051	22,064	23,327	23,500	24,493	23,937	25,555	27,023	30,607	30,532	35,464	33,876	32,044	33,178	37,652	40,101	31,500

Source: EIA SEDS data.

Figure 2.2 Generation by Energy Source, 1990-2006



Note: Renewable energy generation includes approximately 490 GWh of annual geothermal generation that is not directly available to Nevada consumers as it is directly connected to the California power market through connection to Southern California Edison's transmission system.

Figure 2.3 displays the trend in Electricity Sector GHG emissions during the same time period. Compared to natural gas, coal is the predominant GHG emitting source throughout most of the historical period, even though it represents less than half of the power (GWh) produced by 2005. Table 2.6 shows the historic change in generation by energy source between 1990 and 2006. Total generation grew by an annual average of 2.9 percent over the 16 years, while average annual growth in electricity consumption over the same period was 4.8 percent.[17] In Nevada, natural gas generation has had particularly strong growth, increasing by more than nine times from 1990 to 2006. All generation plants constructed during the period are fueled by natural gas. In comparison, coal generation declined by more than half as a result of the temporary shut down of the Mohave power plant. Hydroelectric generation experienced the smallest increase between 1990 and 2006 but the table masks the considerable year-by-year variation from this resource. During the 16-year period, hydro generation ranged from a low of 1,615 GWh in 2004 to a high of 3,166 GWh in 1998.

Figure 2.3 GHG Emissions by Energy Source, 1990-2006

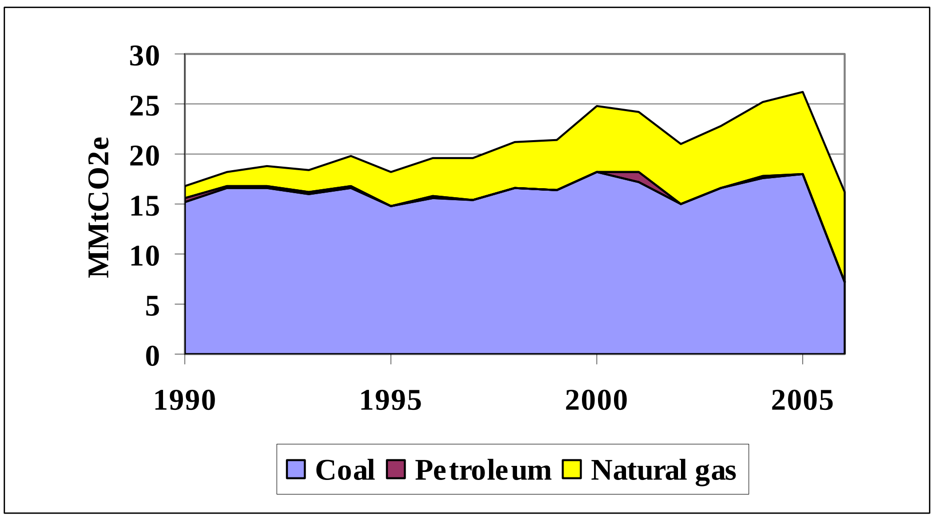


Table 2.6 Change in Electricity Generation in Nevada 1990-2006

	Generation (GWh)		Growth
	1990	2006	
Coal	15,053	7,254	-52%
Hydroelectric	1,735	2,058	19%
Natural Gas	2,217	20,828	839%
Geothermal, solar, wind	761	1,344	77%
Petroleum	284	17	-94%
Total	20,051	32,858	64%

Source: EIA Electric Power Annual Data

[17] EIA SEDS data (1990-2005) and *Electric Power Annual*, State Data Table for 2006.

The majority of the greenhouse gases emitted from the electricity sector between 2000 and 2005 were from five power plants: Eldorado Energy, the Mojave Generating Station, North Valmy, Reid Gardner, and the Tracy Power Plant (see Table 2.7). The highest emitting facilities changed in 2006 to include Chuck Lenzie (which was placed into service in 2006) and Silverhawk after the Mojave generating station was taken out of service at the end of 2005. .

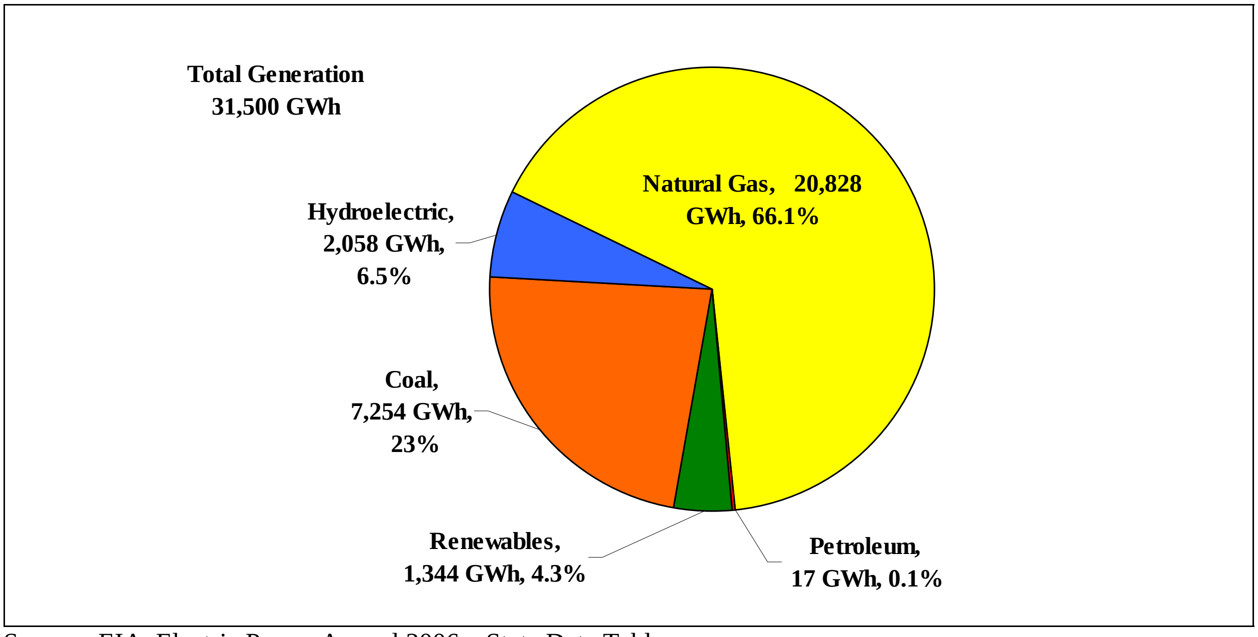
Table 2.7 MMtCO$_2$ Emissions from Individual Nevada Power Plants, 2000-2006

Generation Plant	2000	2001	2002	2003	2004	2005	2006
El Dorado Energy	0.8	0.9	1.3	1.3	1.2	1.3	1.5
Mohave	9.8	9.4	9.2	8.7	9.7	9.8	0.0
North Valmy	3.6	3.4	4.1	3.3	4.0	4.0	3.8
Reid Gardner	4.8	4.4	4.9	5.0	4.8	4.8	5.2
Tracy	1.5	1.7	0.8	0.8	0.9	0.8	0.8
Chuck Lenzie	--	--	--	--	--	--	1.7
Silverhawk	--	--	--	--	--	--	1.3
Other Plants	4.1	4.3	0.6	3.6	4.6	5.5	1.9
Total of All NV Plants	**24.7**	**24.0**	**20.9**	**22.8**	**25.1**	**26.1**	**16.2**

Note: The Mohave plant was removed from service at the end of 2005.
Source: US EPA Clean Air Markets database for named plants (http://cfpub.epa.gov/index.cfm). Total emissions were calculated from fuel use data provided by SEDS (US DOE Energy Information Administration).

As shown in Figure 2.4, coal and natural gas were used to generate the vast majority (almost 90%) of electricity produced in Nevada in 2006.

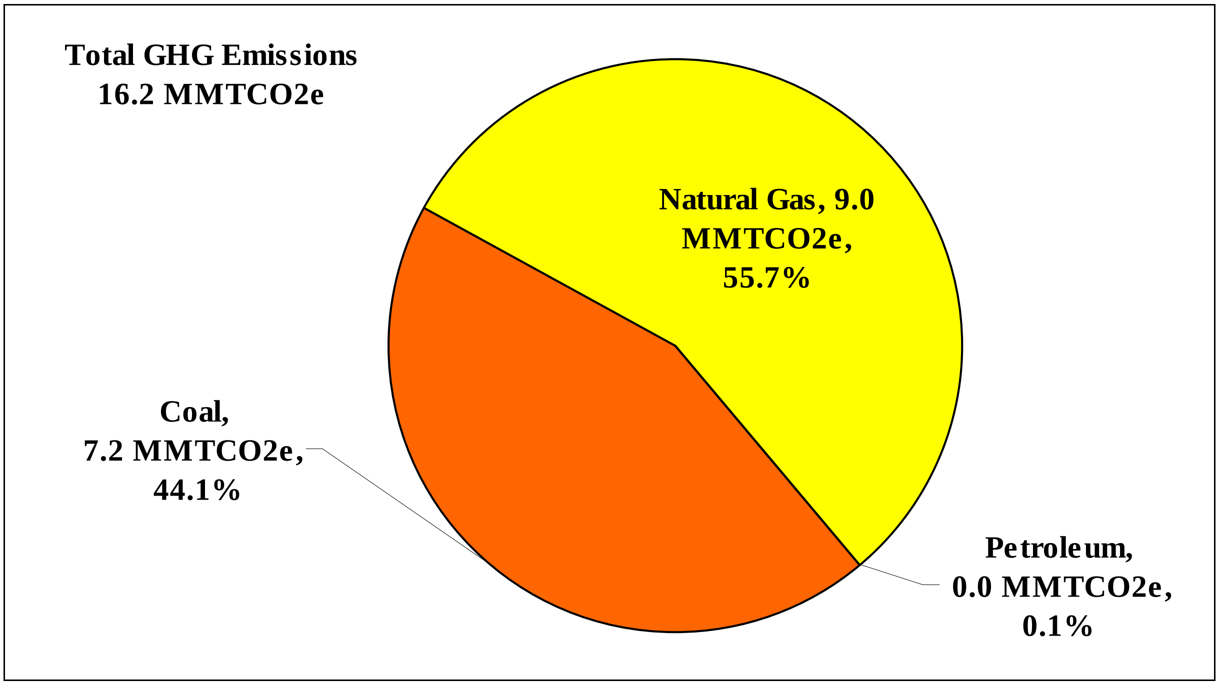
Figure 2.4 Electricity Generation at Nevada Power Plants, 2006*



Source: EIA, Electric Power Annual 2006 – State Data Tables
*= 2006 represents the first year of post-Mohave emissions

Figure 2.5 shows that in 2006, coal accounted for approximately 44% of the GHG emissions from power plants in Nevada. This represents a significant decline from the 69% contributed by coal in 2005. Although the amount of coal-based generation was roughly only a third of that generated by natural gas, generation using coal yields approximately twice the GHG emissions per MWh generated than natural gas.

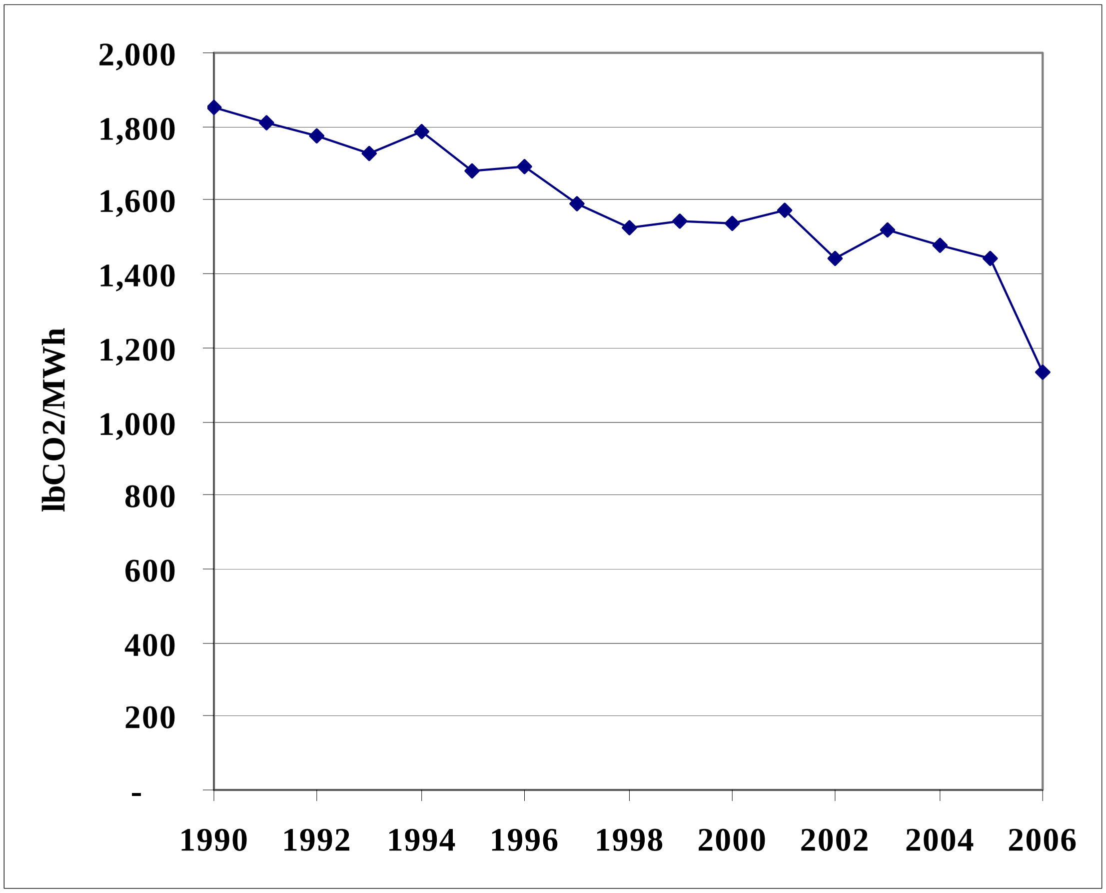
Figure 2. 5 Historic Production-Based Electricity Sector Emissions, 2006



Source: EIA, Electric Power Annual 2006 – State Data Tables
Note: Petroleum emissions are too small to appear in the figure as the emissions total less 0.015 $MMtCO_2e$ and less than 0.1% of statewide emissions.

Figure 2.6 illustrates the historic change in the amount of GHG emissions per megawatt-hour (MWh) of generation. The average carbon intensity of Nevada's generation facilities has declined since 1990 dropping by approximately 23%, from 1,854 lbsCO_2e/MWh in 1990 to 1,440 lbsCO_2e/MWh in 2005. Much of the decline seen between 1990 and 2005 is due to the addition of natural gas-fired generation capacity. The precipitous drop between 2005 and 2006 is the result of the temporary closure of the Mojave Generating Station and is probably not indicative of future intensity levels. As shown in Table 2.2, GHG emissions from the Mohave plant totaled 9.4 MMtCO_2 in 2005, representing approximately 35.9% of all Nevada power plant CO_2 emissions in that year.

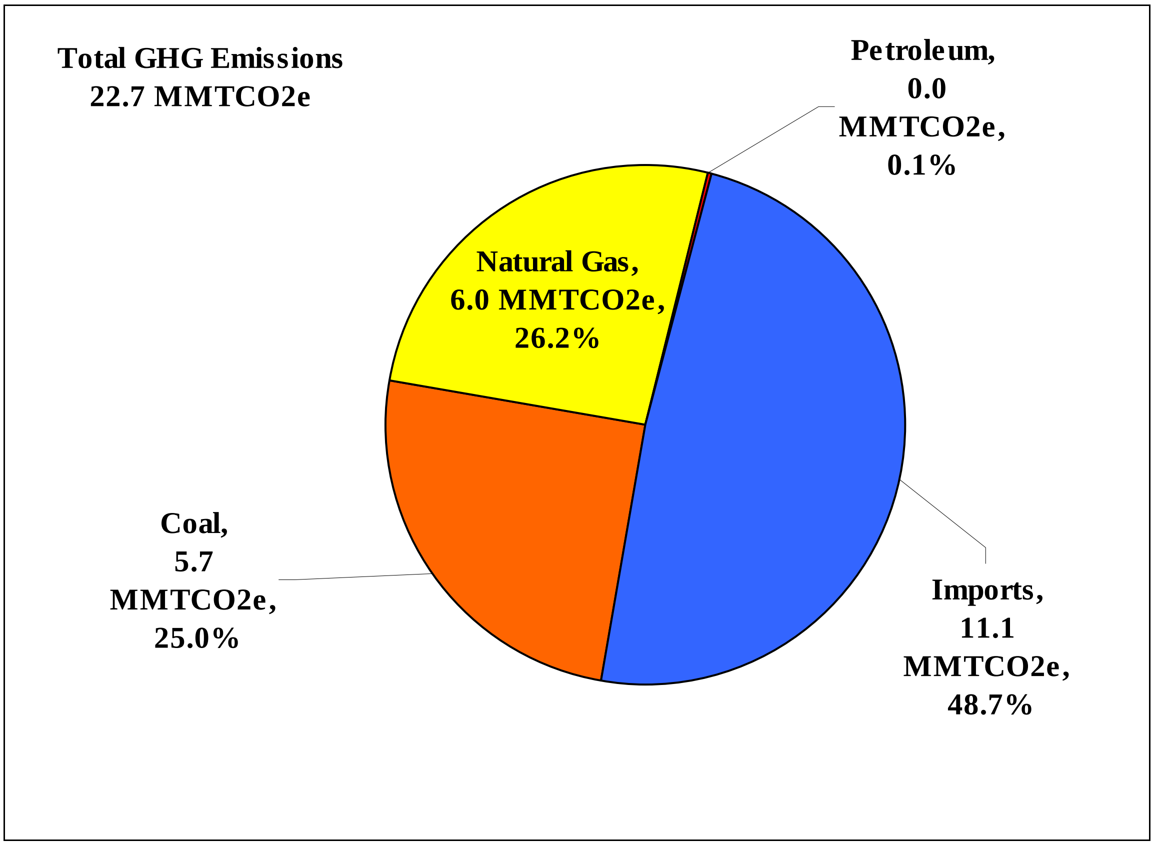
Figure 2.6 Carbon Intensity of Nevada's Electricity Generation, 1990 to 2006



Historic Net-Consumption-Based Emissions

The result of the analysis of 2006 net-consumption-based emissions is presented in Figure 2.7. The figure shows that approximately half of net-consumption based emissions are associated with the in-state generation of electricity, and those emissions are almost evenly split between emissions associated with coal and natural gas fired electricity. The other half of the net-consumption-based emissions are associated with electricity imported to meet the balance of Nevada's needs. The emissions associated with imported electricity were calculated from sub-regional electricity emission rates developed by the WECC.

Figure 2.7 Historic Net-Consumption-Based Electricity Sector Emissions, 2006



Future Production-Based Generation and Emissions

The result of the analysis of production-based emissions estimated under all seven alternative emissions scenarios is presented in Table 2.8 and illustrated in Figure 2.8. The table presents the net increase in both the quantity and percentage of MMtCO_2e emissions from 2006-2015 and 2006-2020. Total emissions in the year 2015 range from a minimum increase of 7.6 MMtCO_2e (Scenarios 1 and 5) to a maximum increase of 25.1 MMtCO_2e (Scenario 4), as compared to 2006 emission levels. Total electric sector GHG emissions in the year 2020 range from a minimum increase of 10.5 MMtCO_2e (Scenario 5) to a maximum increase of 37.3 MMtCO_2e (Scenario 4), as compared to 2006 emission levels. The emissions estimates include an estimate of annual emissions associated with generation plants or EGUs that have been placed into service in 2006 or later.

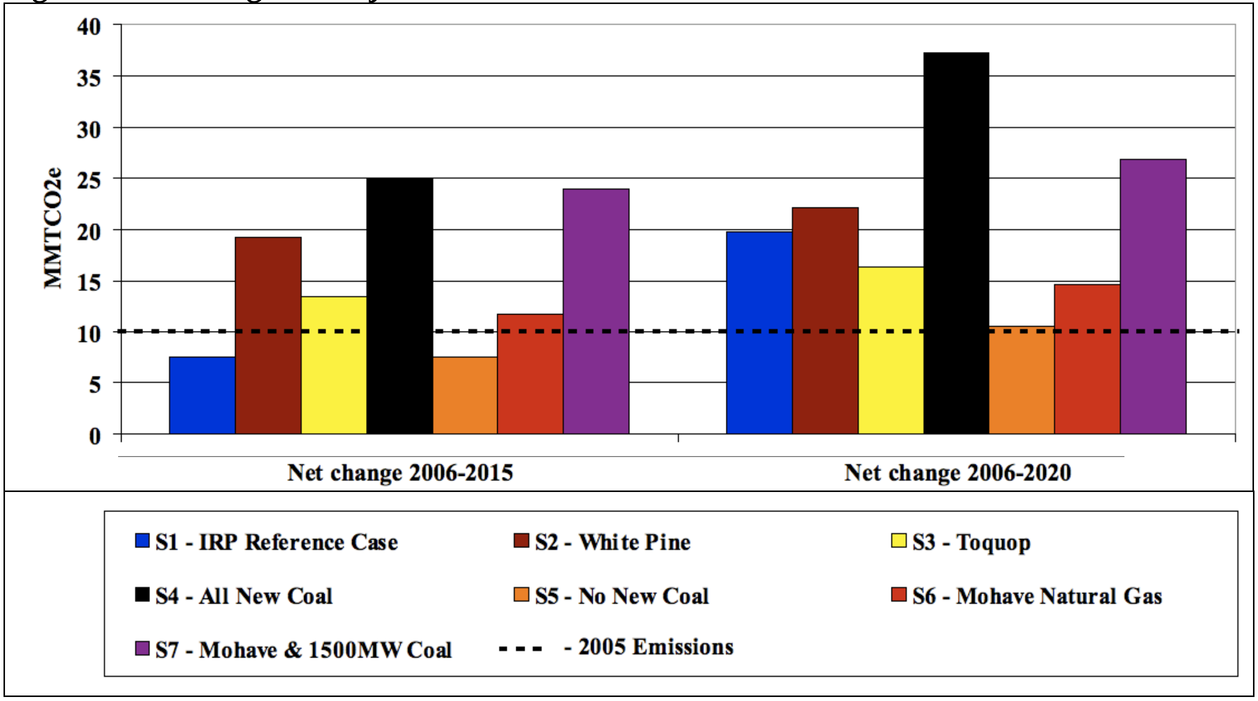
It should be noted that the 2005 electrical generation sector emissions were 26.2 MMtCO_2e, or 10.0 MMtCO2e greater than 2006 emissions levels. The net change in projected emissions from 2005 to 2015 under the same seven emission scenarios ranges from an overall decrease in emissions of 2.4 MMtCO_2e (scenarios S1 and S5) to a net increase of 15.1 MMtCO_2e (scenario S4). The net change in projected emissions from 2005 to 2020 under the same seven emission scenarios ranges from 0.5 MMtCO_2e (scenario S5) to 27.3 MMtCO_2e (scenario S4) (see Figure 2.8).

Full compliance with Nevada's RPS will result in MMtCO_2e reductions of 1.15, 2.58, and 2.90 by the end of 2010, 2015, and 2020, respectively. The specific MMtCO_2e reductions associated with use of renewable energy in the same years are estimated to be 0.73, 1.80, and 2.04. Similarly, the specific emissions reduction related to DSM is estimated to be 0.42, 0.78 and 0.86 MMtCO_2e. These reductions are factored into the levels presented in Table 2.8 and Figure 2.8.

Table 2.8 Change in Projected Emissions From 2006

Electric Sector MMtCO2e Emissions				Net change	Net change	% change	% change
Emission Scenario	2006	2015	2020	2006-2015	2006-2020	2006-2015	2006-2020
S1 - IRP Reference Case	16.2	23.8	36.0	7.6	19.7	46.6%	121.7%
S2 - White Pine	16.2	35.5	38.4	19.2	22.1	118.6%	136.5%
S3 - Toquop	16.2	29.6	32.5	13.4	16.3	82.6%	100.5%
S4 - All New Coal	16.2	41.3	53.5	25.1	37.3	154.6%	229.8%
S5 - No New Coal	16.2	23.8	26.7	7.6	10.5	46.6%	64.5%
S6 - Mohave Natural Gas	16.2	27.9	30.8	11.6	14.5	71.7%	89.6%
S7 - Mohave & 1500MW Coal	16.2	40.2	43.0	23.9	26.8	147.5%	165.4%

Figure 2.8 Change in Projected Emissions from 2006



Note: The 2005 emissions baseline is included for comparison purposes. If projections had been based on the 2005 emissions baseline, then they would be 10 MMt less than projections starting from 2006 levels (some scenarios would even show negative growth through 2015).

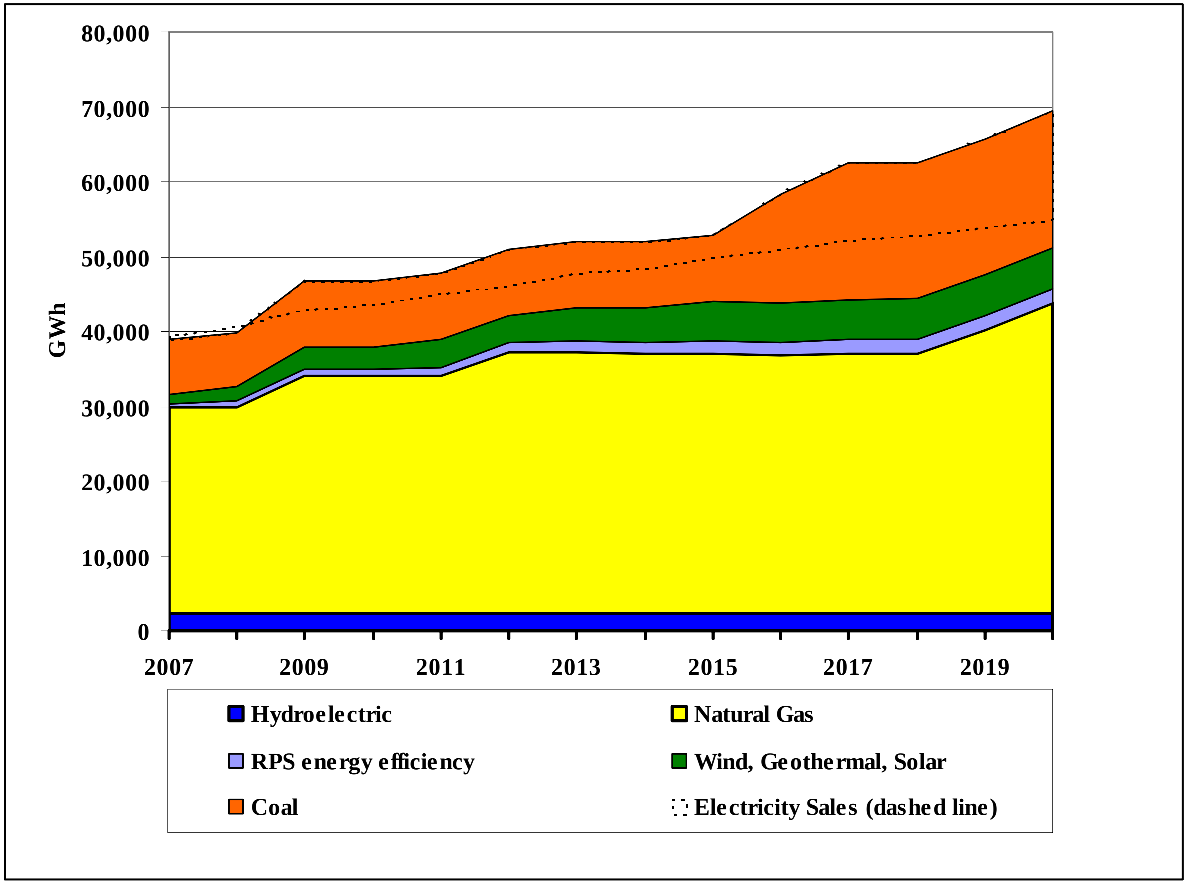
Table 2.9 shows the results of electricity generation projections for the period of 2007-2020, as modeled on the IRP reference case scenario and differentiated by generation source. The generation projections are illustrated in Figure 2.9. The figure includes the amount of electricity demand, represented by the dashed line, and the amount of electricity supplied through demand-side management (DSM) savings. Figure 2.9 shows that the total generation, including the amount of generation avoided by implementation of DSM programs, will exceed total projected in-state electricity sales starting at the end of 2008. It should be noted that Table 2.9 and Figure 2.9 depict only projections of electrical energy generated and consumed *over time* (gigawatt-hours), and not the total electric generation capacity required to meet instantaneous electricity power demand (the number of gigawatts) such as at the hottest hour of the hottest summer day.

The table and figure show that natural gas fired generation will be the dominant source of electricity generated during the projection period, followed by coal fired generation and, to a much smaller extent, an increase in generation contributed by renewable energy resources. The first full year of coal fired electricity generation that is added by NV Energy's Ely Energy Center occurs in 2016 and 2017. NV Energy's Reid Gardner Units 1-3 are expected to be taken out of service by the end of 2016.

Table 2.9 IRP Reference Case Generation 2007-2020

Generation Source	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	7,254	7,254	8,780	8,780	8,780	8,780	8,780	8,780	8,780	14,365	18,191	18,191	18,191	18,191
Hydroelectric	2,227	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292
Natural Gas	27,699	27,699	31,781	31,781	31,740	34,920	34,920	34,783	34,783	34,569	34,805	34,805	37,913	41,467
Petroleum	23	28	34	40	40	35	35	31	31	31	31	31	31	31
Wind, Geo, Solar	1,318	1,899	2,854	2,897	3,671	3,727	4,537	4,606	5,194	5,274	5,355	5,438	5,522	5,607
Total	38,945	39,870	46,685	46,749	47,740	50,990	52,070	52,021	52,805	58,282	62,453	62,563	65,783	69,451

Figure 2.9 IRP Reference Case Generation 2007-2020



Note: Generation from petroleum resources not included in figure because it is too small to be visible.

Future Net-Consumption Based Emissions

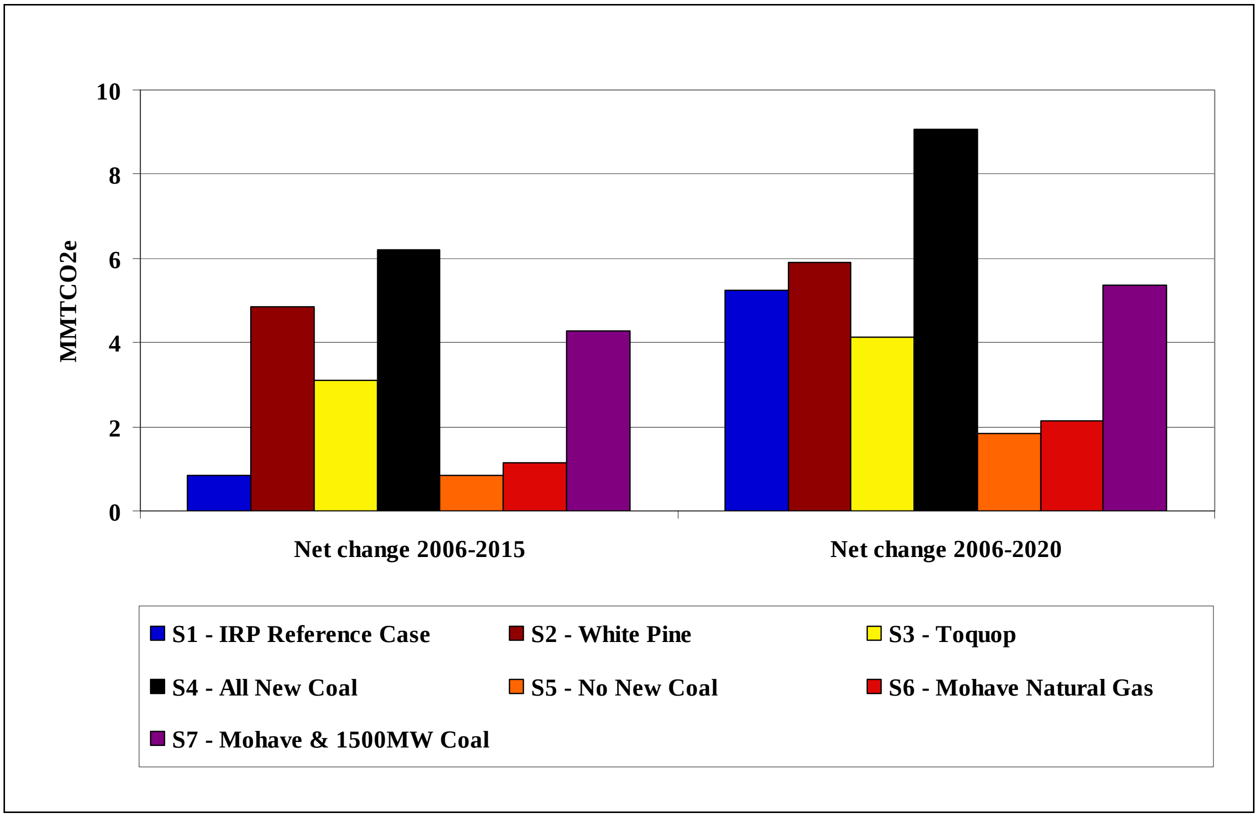
The results of the analyses of net-consumption-based emissions projected for all seven scenarios are presented in Table 2.10 and Figure 2.10. The table presents the net increase in both the quantity and percentage of $MMtCO_2e$ emissions from 2006-2015 and 2006-2020. Total emissions in the year 2015 range from a minimum increase of 0.9 $MMtCO_2e$ (Scenarios 1 and 5) to a maximum increase of 6.2 $MMtCO_2e$ (Scenario 4), as compared to 2006 emission levels. Total electric sector GHG emissions in the year 2020 range from a minimum increase of 1.8 $MMtCO_2e$ (Scenario 5) to a maximum increase of 9.1 $MMtCO_2e$ (Scenario 4), as compared to 2006 emission levels. The emissions estimates include an estimate of annual emissions associated with generation plants or EGUs that have been placed into service in 2006 or later.

Estimation of future net-consumption based emissions assumes full compliance with Nevada's RPS and the associated emissions reductions that are expected due to that requirement.

Table 2.10 Change in Projected Net-Consumption-Based Emissions from 2006

Electric Sector MMtCO2e Emissions				Net change	Net change	% change	% change
Emission Scenario	2006	2015	2020	2006-2015	2006-2020	2006-2015	2006-2020
S1 - IRP Reference Case	22.7	23.6	27.9	0.9	5.2	3.8%	23.1%
S2 - White Pine	22.7	27.6	28.6	4.9	5.9	21.4%	26.1%
S3 - Toquop	22.7	25.8	26.8	3.1	4.1	13.7%	18.2%
S4 - All New Coal	22.7	28.9	31.8	6.2	9.1	27.3%	39.9%
S5 - No New Coal	22.7	23.6	24.5	0.9	1.8	3.8%	8.1%
S6 - Mohave Natural Gas	22.7	23.8	24.8	1.1	2.1	5.0%	9.4%
S7 - Mohave & 1500MW Coal	22.7	27.0	28.1	4.3	5.4	18.8%	23.7%

Figure 2.10 Change in Projected Net-Consumption-Based Emissions from 2006



2.4 UNCERTAINTIES

The process used to estimate future GHG emission estimates through the year 2020 includes two components. The first is that the total level of electricity generation from existing in-state fossil fuel-fired plants in calendar year 2006 is held constant through 2020 except in those years where generation is lost due to scheduled plant retirement as proposed in the IRP reference case.

The second component concerns the emissions of fossil plant additions that occur after 2006, starting in 2008, and those proposed to be added in future years. In this case, assumptions were made regarding the number of plant operating hours as a percentage of the number of hours in a year. This is referred to as plant *capacity factor* and it was assumed that these ranged from 15% for peaking plants to 85% for baseload coal plants (Table 2.2 footnotes). Assumptions were also made regarding plant *heat rate*, which is the amount of electricity produced per MMBtu of heat input. Table 2.1 references the plant heat rates that were used.

Plant capacity factor and heat rate are used together to estimate the quantity of fossil fuel consumed and the resulting GHG emissions. Both of these factors can vary considerably during the year and year-to-year, depending upon numerous factors that affect the number of hours of plant operation, and therefore the quantity of emissions generated. These factors include changes in the price and supply of generating fuels, availability and price of firm and non-firm (spot market) purchased power, atypical weather conditions, transmission constraints, unexpected generating unit outages, and other factors. These factors are of particular consequence to power provider decisions regarding which units in their fleet of generation plants will be operated on any given day and for how long, although the relative operating cost efficiency of each generation plant typically determines the priority of operation scheduling.

Additional uncertainties include changes in marketplace factors, such as large price swings or supply limitations, and actions currently under consideration at regional and national levels to limit or reduce GHG emissions. Implementation of a cap-and-trade program or a carbon tax would be expected to increase the cost of electricity generated from carbon-intensive fuels such as coal and stimulate increased investments in demand-side management programs and generation from natural gas and renewable resources.

3.0 RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL (RCI) SECTOR EMISSIONS

3.1 OVERVIEW

Combined, the residential, commercial, and industrial sectors (RCI) represent the third-largest source of statewide emissions, accounting for approximately 12% of emissions in 2005, but decreasing to approximately 8.8% of total emissions in 2020. This section addresses only the RCI sector emissions associated with the direct use of energy sources (natural gas, petroleum, coal and wood). Emissions associated with RCI sector electricity consumption are presented in Section 2.

The two main emissions producing activities in the RCI[18] sector are fuel combustion to provide space and process heating, and when fuel is used in non-road vehicles (mainly in construction and agriculture).[19] Carbon dioxide accounts for over 99% of these emissions on a million metric tons of carbon dioxide equivalent ($MMtCO_2e$) basis.

Direct use of oil, natural gas, coal, and wood in the total RCI sectors produced approximately 6.8 $MMtCO_2e$ in 2005 and emissions are projected to increase only minimally through 2020 to approximately 6.9 $MMtCO_2e$. Projected growth in population, employment and manufacturing is the key driver responsible for emissions growth in the residential, commercial and industrial sectors, respectively.

3.2 METHODOLOGY

3.2.1 Estimation of Historic Emissions

Historical RCI fuel consumption data is available for the period of 1990-2005 from EIA's State Energy Data System (SEDS). Sector emissions from the combustion of natural gas, petroleum, wood, and coal were estimated using EPA's State Inventory Tool (SIT) following the methods provided in the EIIP guidance document for this sector. CO_2 emissions for fossil fuel combustion in the residential and commercial sectors are calculated by multiplying energy consumption in these sectors by carbon content coefficients for each fuel. These quantities are then multiplied by fuel-specific percentages of carbon oxidized during combustion (a measure of combustion efficiency). The resulting fuel emission values, in pounds of carbon, are then converted to $MMtCO_2e$.

Industrial sector emissions are calculated in the same way, except emissions from fossil fuels not used for energy production are factored separately. Non-energy sector consumption of fossil fuel is first subtracted from total fuels and multiplied by carbon storage factors for each fuel type. This is necessary because a portion of the fossil fuel is

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

[19] Emission estimates from wood combustion include only N_2O and CH_4. Carbon dioxide emissions from biomass combustion are assumed to be "net zero", consistent with U.S. 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.

used for non-energy uses and can be sequestered (stored) for a significant period of time (e.g., more than 20 years). For example, LPG is used for the production of solvents and synthetic rubber, and oil is used to produce asphalt, napthas, and lubricants. Pursuant to the EIIP, the carbon that is stored is assumed to remain unoxidized for long periods of time, meaning that the carbon is not converted to CO_2. After the portion of stored carbon is subtracted, the resulting (net) combustible consumption for each fuel is then used to calculate industrial sector emissions.

The general equation used for converting residential and commercial energy consumption to $MMTCO_2e$ is as follows:

*Billion Btu Consumed * Emission Factor (lbs C / Million Btu) * Combustion Efficiency (%) = Emissions (short tons of carbon)*

*Emissions (short tons of carbon) * 0.9072 * 1/1,000,000 = MMtCO2e*

Equation Legend:
Billion Btu consumed refers to the total heat content of the applicable fuel.
Emission factor refers to the conversion factor used to convert total heat content of the quantity of fuel consumed to pounds of carbon.
Combustion efficiency refers to the percentage completeness of the combustion of the applicable fuel.
0.9072 is a constant used to convert from short tons to metric tons.

The general equation used for converting industrial energy consumption to $MMtCO_2e$ is as follows:

*Billion Btu Consumed – Non-Energy Billion Btu Consumed * Storage Factor (%) = Billion Btu Net Combustible Consumption*

*Billion Btu Net Combustible Consumption * Emission Factor (lbs C / Million Btu) * Combustion Efficiency (%) = Emissions (short tons of carbon)*

*Emissions (short tons of carbon) * 0.9072 * 1/1,000,000 = MMtCO2e*

Equation Legend:
Billion Btu consumed refers to the total heat content of the applicable fuel.
Non-Energy Billion Btu Consumed refers to heat content portion of fossil fuel consumed that is stored as opposed to combusted, therefore no greenhouse gas emissions occur.
Billion Btu Net Combustible Consumption refers to the heat content portion of fossil fuel consumed that is combusted and results in greenhouse gas emissions.
Emission factor refers to the fuel-specific conversion factor used to convert total heat content of the quantity of fuel consumed to pounds of carbon.
Combustion efficiency refers to the percentage completeness of the combustion of the applicable fuel.
0.9072 is a constant used to convert from short tons to metric tons.

The fossil fuel categories used to determine non-combustion RCI emissions (to which the EIIP methods are applied in the SIT 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,[20] petroleum coke, residual fuel, still gas, and waxes. Data on annual use of the fuels in these categories as chemical industry feedstocks were obtained from the SEDS data.

3.2.2 Estimation of Projected Emissions

Reference case projections of emissions from direct fuel combustion were mainly based on fuel consumption forecasts developed by the EIA as contained in the AEO2008. Nevada is included in the EIA fuel consumption forecast for the Mountain Region, which was used for this analysis. In an effort to produce a Nevada-specific forecast of future fuel consumption, additional information on population and employment trends was needed for the calculations. The Nevada State Demographer's Office provided population growth forecasts.[21] The population forecasts were used to normalize the EIA regional projections of fuel consumption for Nevada's residential sector in five-year increments.

Nevada employment data for the manufacturing (goods-producing) and non-manufacturing (commercial or services-providing) sectors were obtained from the Nevada Department of Employment, Training, and Rehabilitation (DETR).[22] Regional employment data for the same sectors were obtained from EIA for the EIA's Mountain Region.[23] The DETR employment projections were used to normalize the EIA regional projections of fuel consumption for Nevada's commercial and industrial sectors.

Based on the DETR's 10-year forecast (2006 to 2016), the annual commercial employment growth rate was assumed to decrease by 0.16%, while industrial employment was projected to increase at an annual rate of 0.35%. These growth rates were used to obtain the growth rates in energy use shown in Table 3.1. The 2006 to 2016

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

21 Population data for 1990 through 2005 from the Nevada State Demographer's Office, University of Nevada, Reno, Nevada, "Nevada County Population Estimates July 1, 1990 to July 1, 2005 Includes Cities and Towns" (http://www.nsbdc.org/what/data_statistics/demographer/pubs/pdfs/NVpopul05.pdf). Population forecasts for 2006 to 2020 also from the Nevada State Demographer's Office, University of Nevada, Reno, Nevada, "Nevada County Population Projections 2008 to 2028" (http://www.nsbdc.org/what/data_statistics/demographer/pubs/docs/NV_Projections_2008_Report.pdf)

22 Employment data for 2000 through 2006 from Nevada Department of Employment, Training & Rehabilitation; Nevada Workforce Informer; Current Employment Statistics (http://www.nevadaworkforce.com/cgi/dataanalysis/): Select Data Analysis, Current Employment Statistics, Select Years = 2000 – 2006, Select Time Periods = Annual, Select Industries = Goods Producing, Services Providing, Select Seasonally Adjusted = Not, Select Data Series = No. of Employed, Select View Data, Select Download = Text. Employment Data for 2006 and 2016, Nevada Department of Employment, Training & Rehabilitation; Nevada Workforce Informer; Current Employment Statistics (http://www.nevadaworkforce.com/cgi/dataanalysis/): Select 10 Year Industry Employment Projections, Select Area Types = Nevada, Select Areas = Nevada, Select Time Periods = 2006-2016, Select Industry Code Type = NAICS, Select One or More Industries = Goods-Producing, Services-Providing, Select Data Series = Estimated Employment and Projected Employment, Select View Data, Select Download = Text.

23 AEO2008 employment projections for EIA's mountain region obtained through personal communication with EIA (Kay Smith), November 10, 2008.

commercial and industrial employment growth rates were carried forward to 2020. These estimates of growth relative to population and employment, and the commensurate changes in fuel use, are expected to be the primary factors affecting future GHG emissions in the RCI sectors.

However, changing fuel prices, evolving technologies, as well as structural changes within each sector (such as shifts in energy use patterns) are also reflected, to a smaller degree, in the EIA analysis that formed the basis for the emissions projections. Table 3.1 shows that in Nevada's residential sector, use of natural gas is projected to increase, while petroleum use, which includes propane and fuel oil, will remain largely unchanged.

Use of wood and coal in the residential sector is expected to decrease from 2005 through 2020 (the small increase in coal use projected by the EIA during 2005 to 2010 is thought to be due to the forecasted increase in population in the Mountain Region). Residential fuel use in Nevada follows the expected national trend of increased use of the cleaner and more efficient natural gas and diminished use of less efficient wood and coal fuels.

Fuel use in the commercial sector is expected to decrease, principally due to improvements in efficiency and a slight contraction in expected employment in this sector. Projected industrial sector fuel use roughly follows the commercial sector, however, use of wood (biomass) has seen a marked expansion since the mid 1990s as an industrial fuel and that trend is expected to continue.

Table 3.1 Historic and Projected Average Annual Growth Rate in Energy Use in Nevada, by Sector and Fuel, 1990-2020

	1990-2005[a]	2005-2010[b]	2010-2015[b]	2015-2020[b]
Residential				
Natural gas	5.3%	2.6%	1.9%	1.0%
Petroleum	-1.1%	0.1%	0.3%	0.1%
Wood	-0.3%	1.0%	-1.3%	-1.3%
Coal	-13.5%	2.7%	-0.6%	-1.1%
Commercial				
Natural gas	4.0%	-1.9%	0.2%	-0.1%
Petroleum	2.2%	-4.2%	-0.7%	-1.2%
Wood	2.4%	-2.4%	-1.7%	-1.5%
Coal	-8.0%	-2.2%	-1.7%	-1.5%
Industrial				
Natural gas	4.3%	-0.3%	-1.1%	-1.4%
Petroleum	0.1%	-0.2%	-1.8%	0.5%
Wood[c]	8.8%	2.4%	0.1%	1.7%
Coal	1.1%	-0.2%	-2.9%	-0.9%

[a] Compound annual growth rates calculated from EIA SED historical consumption by sector and fuel type for Nevada. Petroleum includes distillate fuel, kerosene, and liquefied petroleum gases for all sectors plus residual oil for the commercial and industrial sectors.

[b] Figures for growth periods starting after 2005 are calculated from AEO2008 projections for EIA's Mountain region, adjusted for Nevada's projected population for the residential sector, projections for service sector employment for the commercial sector, and projections for manufacturing and non-manufacturing employment for the industrial sector.

[c] Industrial wood consumption is zero for 1990 through 1995; industrial wood consumption growth rate is based on SED information reported for 1996 through 2005.

3.3 RESULTS

Table 3.2 and Figure 3.1 show the historic and projected emissions for the RCI sectors in Nevada from 1990 through 2020. GHG emissions associated with electricity consumed by the combined total of the three sectors are included in Section 2 of this report. On-road vehicle, aviation, marine vessel and rail transportation GHG emissions associated with RCI sector transportation energy consumption are included in the emission total presented in Section 4.

The combined RCI sector emissions at the beginning of the historical period were estimated at approximately 4.4 $MMtCO_2$, growing to 6.8 $MMtCO_2$ by the end of 2005. In that year, residential, commercial and industrial sector GHG emissions were estimated at approximately 2.3, 1.7, and 2.8 $MMtCO_2e$, respectively.

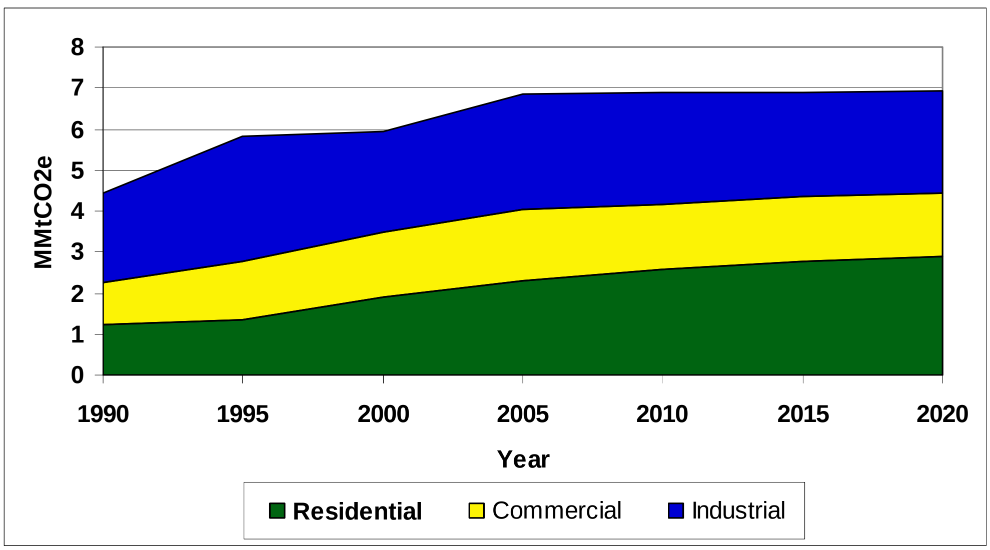
The combined RCI sector emissions are projected to increase by 0.11% annually, reaching approximately 6.9 $MMtCO_2e$ at the end of the projection period in 2020. The residential sector emissions are projected to increase by 1.52% per year to approximately 2.9 $MMtCO_2e$ in 2020. The commercial and industrial sector emissions are both projected to decrease, by approximately 0.70% and 0.75% per year, respectively. As a result, by the end of the projection period in 2020 commercial sector emissions are projected to be approximately 1.6 $MMtCO_2e$ and industrial sector emissions are projected to be approximately 2.5 $MMtCO_2e$.

GHG emissions projections in the RCI sector are largely based on the assumption that changes in population and employment growth directly impact energy consumption and associated GHG emissions. Therefore, residential sector emissions are expected to increase over the projection period, but commercial and industrial sector emissions are both projected to decrease.

Table 3.2 Historic and Projected RCI Sector GHG Emissions, 1990-2020

	1990	1995	2000	2005	2010	2015	2020
Residential	1.24	1.35	1.88	2.30	2.56	2.77	2.88
Commercial	1.03	1.41	1.61	1.74	1.59	1.59	1.56
Industrial	2.15	3.07	2.47	2.80	2.72	2.53	2.50
Total	4.42	5.84	5.96	6.83	6.87	6.89	6.94

Figure 3.1 Historic and Projected RCI Sector GHG Emissions, 1990-2020



3.4 UNCERTAINTIES

Population and economic growth are the principal drivers for RCI sector fuel use. Sources of fuel consumption projections specific to Nevada could not be identified. As stated earlier, the EIA's reference case fuel consumption projections for the Mountain Region were used and rescaled based on Nevada population and employment growth projections. Consequently, there are significant uncertainties associated with the projections of future fuel use in Nevada. Fuel consumption data specific to Nevada will be incorporated as it becomes available in subsequent updates to the statewide GHG inventory and projections report.

Secondly, the AEO2008 projections assume no large, long-term changes in fuel prices, relative to current price levels. Significant price shifts 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.

4.0 TRANSPORTATION SECTOR EMISSIONS

4.1 OVERVIEW

The transportation sector is the second-largest source of statewide GHG emissions, accounting for approximately 30.1% of total emissions in 2005. Emissions generated by this sector are the result of fossil-fuel consumed primarily by vehicles and aircraft. By 2020, transportation is expected to account for 33.2% of statewide GHG emissions. This is due mainly to projections that the growth in vehicle-miles-traveled (VMT) observed in recent years will continue into the future. Nevada's cities have grown and their suburban fringe has expanded outward, leading to a steady increase in the distances traveled. Growth in Nevada's population and commercial sector activity has added to the number of vehicles on the roadway. Though the long-term effect that both the 2008 spike in fuel prices, and the current economic downturn, will have on VMT growth is unclear at this time, transportation sector emissions are forecast to increase.

For 2005, carbon dioxide accounted for approximately 98% of transportation sector emissions, with N_2O emissions from gasoline engines accounting for almost all of the balance of sector emissions. It should be noted that non-road vehicle fuel consumption and associated emissions are addressed in the RCI section discussion of this report (Section 3). Nevada's transportation sector GHG emissions were estimated at 16.9 $MMtCO_2e$ in 2005 and are projected to reach 26.0 $MMtCO_2e$ in 2020, an increase of 9.1 $MMtCO_2e$ (54%). The majority of the increase, 7.6 $MMtCO_2e$, is due to on-road vehicle emissions. Almost all (92%) of the remainder of the increase, 1.5 $MMtCO_2e$, is associated with jet and aviation fuel emissions.

4.2 METHODOLOGY

4.2.1 Estimation of Historic Emissions

Historical transportation fuel consumption data is available from the EIA's SEDS database for the period of 1990-2005. Using these data, sector historical emissions for this period were estimated using EPA's SIT tool and the methods provided in the Emissions Inventory Improvement Program (EIIP) guidance document for this sector. CO_2 emissions from fossil fuel combustion in the transportation sector are calculated by multiplying energy consumption by carbon content coefficients for each fuel. These quantities are then multiplied by a measure of their combustion efficiency (a fuel-specific percentage of carbon oxidized during combustion). The resulting fuel emissions, in pounds of carbon, are then converted to million metric tons of carbon dioxide equivalent ($MMtCO_2e$).

The general equation used for converting transportation energy consumption to $MMtCO_2e$ is as follows:

*Billion Btu Consumed * Emission Factor (lbs C / Million Btu) * Combustion Efficiency (%) = Emissions (short tons of carbon)*

*Emissions (short tons of carbon) * 0.9072 * 1/1,000,000 = MMtCO2e*

Equation Legend:
Billion Btu consumed refers to the total heat content of the applicable fuel.
Emission factor refers to the conversion factor used to convert total heat content of the quantity of fuel consumed to pounds of carbon.
Combustion efficiency refers to the percentage completeness of the combustion of the applicable fuel.
0.9072 is a constant used to convert from short tons to metric tons.

Different calculations are required to determine N_2O emissions from gasoline engines. N_2O emissions from gasoline engines are calculated based on the quantity of emissions per mile traveled and are dependent upon vehicle type, age and vehicle emission control technology. Historic GHG emissions estimates were calculated using historic sector fuel consumption data available through 2005, as incorporated in EPA's SIT and as updated where necessary with data from the EIA SEDS.

4.2.2 Estimation of Projected Emissions

The calculation of projected on-road gasoline and diesel emissions was based on 2005 VMT data, provided by the Nevada Department of Transportation. The 2005 VMT data are broken down by EPA-specified vehicle class. The EIA's Annual Energy Outlook 2008 (AEO2008) provides national estimates of VMT growth, which are applied to the 2005 VMT data to estimate future vehicle mix in the various vehicle classes.

The Western Regional Air Partnership (WRAP) mobile source emission inventory[24] provides total projected VMT for Nevada. These data include estimates provided by the Regional Transportation Commissions of Southern Nevada and Washoe County (accounting for Clark County and Washoe County respectively), and estimates of VMT derived for the other 15 counties in Nevada.

These VMT projections suggest a future growth rate of approximately 3.3% per year. VMT projections were adjusted by using the relative percentages of future vehicle mix in each vehicle class and then adjusted downward through the use of projected future improvements in vehicle fuel efficiency to simulate a decrease in VMT and associated fuel consumption. The adjusted VMT projections were then used to calculate annual average growth rates, which were in turn applied to historical fuel consumption (EIA SEDS data) to obtain projections of fuel use and associated emissions in future years. Table 4.1 on the following page includes the compound annual growth in statewide VMT by vehicle class.

[24] Western Regional Air Partnership, *WRAP Mobile Source Emission Inventories Update*, May 2006. http://www.wrapair.org/forums/ef/UMSI/index.html

Table 4.1 Nevada Vehicle Miles Traveled Compound Annual Growth Rates

Vehicle Class	2005-2010	2010-2015	2015-2020
Heavy Duty Diesel Vehicle	4.49%	4.24%	3.83%
Heavy Duty Gasoline Vehicle	2.33%	3.55%	3.17%
Light Duty Diesel Truck	8.81%	11.62%	12.91%
Light Duty Diesel Vehicle	8.93%	11.62%	12.91%
Light Duty Gasoline Truck	2.40%	3.02%	2.92%
Light Duty Gasoline Vehicle	2.40%	3.02%	2.92%
Motorcycle	2.53%	3.02%	2.92%

The EIIP guidance on inventory preparation recommends that GHG emissions from the combustion of biofuels be subtracted from historical emissions. Because ethanol is a biofuel, gasoline consumption estimates for 1990-2005 were adjusted by subtracting state ethanol consumption pursuant to the EIIP guidance document. Biodiesel is also considered a biofuel and therefore its consumption should similarly be subtracted from the total volume of diesel consumption. However, the quantity of biodiesel could not be subtracted because biodiesel consumption data is not currently reported. Recent federal mandates require the blending of ethanol with gasoline, and use of biodiesel fuel as an alternative to diesel fuel has been increasing. As a result, emissions forecasts may be overstated.

Historical fuel use data for aircraft were available for 1990 through 2005 from the EIA SEDS database. Emissions for this period were calculated using the SIT tool. Aircraft emissions were projected for the period of 2006 to 2020 using itinerant operations provided by the Federal Aviation Administration's (FAA) *Terminal Area Forecast Summary*.[25] Itinerant operations represent the takeoffs and landings of aircraft traveling from one airport to another - as opposed to local operations consisting primarily of practice operations - and include commercial air carrier, commuter, air taxi, general aviation and military operations. The FAA projections of the rate of growth in aircraft itinerant operations provide a reasonable method for estimating future aviation fuel use and associated aircraft emissions.

To estimate projected changes in jet fuel consumption, itinerant operations relating to air carrier, air taxi/commuter, and military aircraft were first summed for each year. The post-2005 estimates were adjusted to reflect the projected increase in national aircraft fuel efficiency

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25 Federal Aviation Administration. *Terminal Area Forecast Summary*, Fiscal Years 2007-2025. http://www.apo.data.faa.gov/main/taf.asp

(indicated by an increased number of seat miles per gallon), as reported in AEO2008. Because AEO2008 does not estimate fuel efficiency changes for general aviation aircraft, forecast changes in the efficiency of aviation gasoline consumption were based solely on the projected commercial and military itinerant operations. These projections resulted in annual growth rates of 2.8% for aviation gasoline and 2.7% for jet fuel. These projections of aviation fuel use for the 2006 through 2020 timeframe were then used to estimate future aircraft emissions.

For the rail and marine sectors, 1990 – 2005 emissions estimates are based on SIT methods and fuel consumption from EIA. For rail, the historic data show no significant positive or negative trend. The historic marine sector gasoline consumption data show growth from 1990 to 2000; however, there was no growth between 2000 and 2005. Therefore, no growth was projected for these two sectors. Table 4.2 summarizes the sector emissions estimations methodology and data sources by vehicle type and greenhouse gas.

Table 4.2 Transportation Sector Emissions Estimation Methodology and Data Sources

Vehicle Type and Greenhouse Gas	Methods and Data
Onroad gasoline, diesel, natural gas, and LPG vehicles – CO_2	**Inventory (1990 – 2005):** EPA SIT and fuel consumption from EIA SED **Reference Case Projections (2006 – 2020):** Gasoline and diesel fuel consumption is based on vehicle miles traveled (VMT) projections from the Western Regional Air Partnership (WRAP), adjusted by fuel efficiency improvement projections from AEO2008. Other on-road fuel consumption is based on Mountain Region fuel consumption projections from EIA AEO2008 adjusted using state-to-regional ratio of population growth.
Onroad gasoline and diesel vehicles – CH_4 and N_2O	**Inventory (1990 – 2005)** EPA SIT, on road vehicle CH_4 and N_2O emission factors by vehicle type and technology type within SIT were updated to the latest factors used in the US EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. State total VMT included in the SIT was replaced with historical VMT data provided directly by NDOT for the purpose of ensuring consistency with state data sources, and then allocated to vehicle types using the default distribution percentages used in the SIT. **Reference Case Projections (2006 – 2020)** VMT projections from MPOs and the WRAP.

Table 4.2 Transportation Sector Emissions Estimation Methodology and Data Sources (Cont.)

Vehicle Type and Greenhouse Gas	Methods and Data
Non-highway fuel consumption (jet aircraft, gasoline-fueled piston aircraft, boats, locomotives) – CO_2, CH_4 and N_2O	**Inventory (1990 – 2005)** EPA SIT and fuel consumption from EIA SED. **Reference Case Projections (2006 – 2020)** Aircraft fuel consumption is based on aircraft operations projections from Federal Aviation Administration (FAA) and jet fuel efficiency improvement projections from AEO2008.

4.3 RESULTS

Historical Emissions

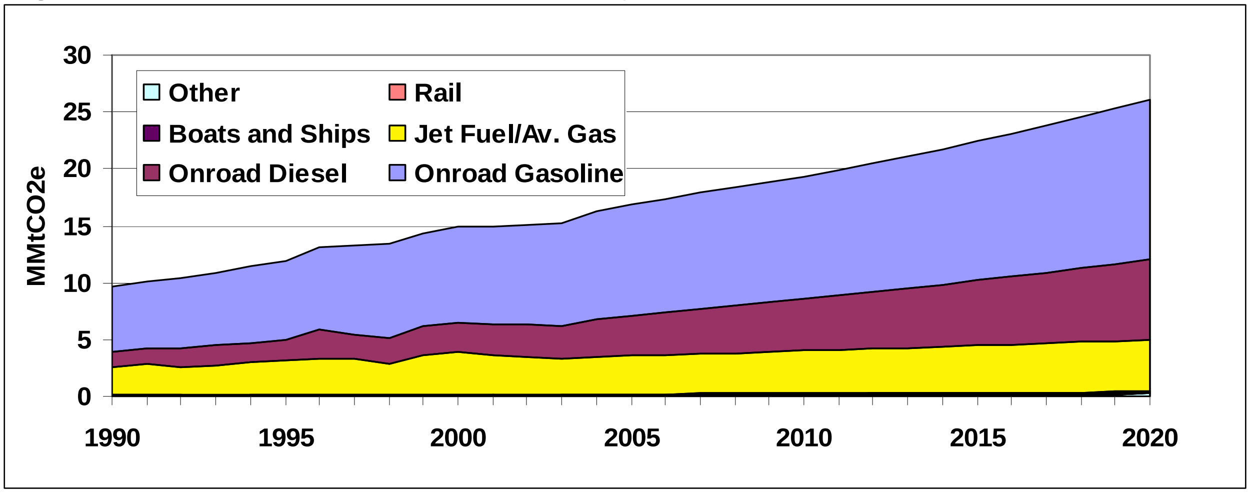
As shown in Figure 4.1, on-road gasoline consumption accounts for the largest share of transportation GHG emissions. Emissions from on-road gasoline vehicles increased by approximately 43% from 1990-2005 and represent approximately 53.6% of total transportation emissions in 2005. GHG emissions from on-road diesel fuel consumption increased by 97% from 1990 to 2005, and by 2005 accounted for 27.2% of total sector emissions. Emissions from aviation fuel consumption – both gasoline and jet fuel - grew by 37% from 1990-2005, accounting for 17.7% of transportation sector emissions in 2005. Emissions from all other categories combined (boats and ships, locomotives, vehicles fueled by natural gas and LPG, and oxidation of lubricants) contributed only 1.5% of total transportation emissions in 2005.

Projected Emissions

The VMT projections suggest that the overall state VMT will grow at a rate of 3.3% per year during the 2006-2020 projection period. The projections suggest on-road fuel consumption growth rates of approximately 1.1% per year for gasoline and approximately 4.8% per year for diesel. The projections also suggest annual average growth rates of 2.8% for aviation gasoline and 2.7% for jet fuel.

Estimated transportation sector emissions for the period of 1990-2020 are graphed in Figure 4.1. GHG emissions from on-road gasoline and diesel consumption are projected to increase by approximately 42.6% and 97.1%, respectively, between 2005 and 2020. GHG emissions from the combined consumption of aviation gasoline and jet fuel during the same period are projected to increase by 37.0%. Total sector-wide emissions are projected to increase by an annual average of 3% from 2006 to 2020. Carbon dioxide uniformly accounts for approximately 96-98% of historical and projected transportation sector emissions.

Figure 4.1 Transportation GHG Emissions by Fuel, 1990-2020



Note: Marine, rail and "other" emissions are too small to be readily observed in the figure.

4.4 UNCERTAINTIES

Vehicle class-specific data on both fuel efficiency and annual miles traveled are not currently collected on a statewide basis in Nevada. This lack of state-specific vehicle class VMT data reduces the accuracy of both present and future yearly on-road vehicle emissions estimates. In the absence of such specific data, national values and growth rates were used to calculate on-road GHG emissions estimates. The national values and growth rates may not accurately reflect the total amount of VMT traveled by each vehicle class in Nevada.

Increasing trends to substitute biodiesel (in part or completely) for petro-diesel are not included in forecasts of VMT emissions. Neither national nor statewide biodiesel consumption data is collected at the present time. The projected growth rate in Nevada diesel consumption may be slightly overestimated because increased substitution of biodiesel in the future.

Aviation emissions estimates are potentially overstated because fuel consumed by international flights departing from Nevada (international bunker fuel) could not be excluded from statewide fuel use estimates. Specific data are not available to subtract the consumption of this fuel from total jet fuel consumption estimates. Also, Nevada military aviation fuel procurement officers were unable to provide projections of fuel consumption for more than a year or two. For this reason, projected GHG emissions were instead held constant at the historical operation level of military aircraft operations included in the FAA's *Terminal Area Forecast Summary*.

Most importantly, fluctuations in fuel prices have dramatic impacts on fuel use in different transportation sectors. Even minor changes to fuel prices, in any or all sectors, could significantly alter future GHG emissions projections.

5.0 INDUSTRIAL PROCESS SECTOR EMISSIONS

5.1 OVERVIEW

Emissions in the industrial processes category span a wide range of activities for many sectors, but do not include sources of GHG emissions emanating from the combustion of fossil fuels. They include emissions associated with the four main industrial processes that occur in the state. These are: 1) CO_2 emitted from production of cement and lime and the consumption of limestone, dolomite, and soda ash; 2) N_2O emissions from nitric acid production used to manufacture explosives; 3) sulfur hexafluoride (SF6) emitted from transformers used in electric power transmission and distribution (T&D) systems; and, 4) hydrofluorocarbon (HFC) and perfluorocarbon (PFC) emissions resulting from the consumption of substitutes for ozone-depleting substances (ODS) used in cooling and refrigeration equipment.

Nevada's total industrial process GHG emissions were estimated at 2.5 $MMtCO_2e$ in 2005 and are projected to reach 4.6 $MMtCO_2e$ in 2020, an increase of 184%. These totals represent approximately 4.5% of statewide GHG emissions in 2005 and 5.9% in 2020. The forecast increase in sector emissions is primarily the result of the increased emissions from the use of substitutes for ozone-depleting substances (ODS). HFCs and PFCs are used as refrigerants in stationary and mobile cooling equipment applications.

5.2 METHODOLOGY

GHG emissions for 1990 through 2005 were estimated using SIT and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for this sector.[26] Table 5.1 on the following page, further identifies for each emissions source category, the industrial activity data required to calculate sector GHG emissions using SIT, the data sources used, and the historical years for which emissions were calculated based on the availability of data. Table 5.2 includes sources of data used for emission projections, assumptions on future growth of industrial activity, and annual emissions growth rates projected for a variety of future time periods. All data come from NDEP, Clark County Department of Air Quality and Environmental Management (DAQEM), and Washoe County District Health Department sources.

[26] GHG emissions were calculated using SIT, with reference to the Emission Inventory Improvement Program, Volume VIII: Chapter. 6. "Methods for Estimating Non-Energy Greenhouse Gas Emissions from Industrial Processes", August 2004.

Table 5.1 Approach Used in Estimating Historical Emissions

Source Category	Time Period	Required Data for SIT	Data Source
Cement Manufacturing - Clinker Production	1994 – 2002	Metric tons of clinker (an intermediate product from which finished Portland and masonry cement are made) produced each year.	-- The NDEP provided annual clinker production data for 1994 – 2005 for Nevada Cement (production data were not available for years prior to 1994). -- Clark County had one plant (Royal Cement) that closed in 2004, but the County did not have any clinker production data for the plant. Therefore, historical emissions were not estimated for this plant. --Washoe County does not have any cement plants.
Cement Manufacturing - Masonry Cement Production	1994-2005	Metric tons of masonry cement produced each year.	-- The NDEP confirmed that masonry cement is not manufactured by Nevada Cement. -- Clark County staff believe that the Royal Cement plant, which closed in 2004, did not produce masonry cement. -- Washoe County does not have any cement plants.
Lime Manufacture	1994 - 2005	Metric tons of high-calcium and dolomitic lime produced each year.	-- The NDEP provided annual high-calcium lime production data for 1994 – 2005 for Graymont Western (production data were not available prior to 1994). -- Clark County provided annual high-calcium and dolomitic lime production data for Chemical Lime Company for 1999, 2000, 2001, and 2003. -- Washoe County does not have any lime plants.
Limestone and Dolomite Consumption	1994 – 2002	Consumption of limestone and dolomite by industrial sectors.	For default data, the state's total limestone consumption (as reported by USGS) is multiplied by the ratio of national limestone consumption for industrial uses to total national limestone consumption. Additional information on these calculations, including a definition of industrial uses, is available in Chapter 6 of the EIIP guidance document.

Table 5.1 Approach Used in Estimating Historical Emissions (Cont.)

Source Category	Time Period	Required Data for SIT	Data Source
Soda Ash Consumption	1990 – 2005	Consumption of soda ash used in consumer products such as glass, soap and detergents, paper, textiles, and food. Emissions based on state's population and estimates of emissions per capita from the US EPA national GHG inventory.	USGS Minerals Yearbook, 2004: Volume I, Metals and Minerals, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/). For population data, see references for ODS substitutes.
Nitric Acid Production	1994-2005	Metric tons of nitric acid produced each year.	NDEP provided annual production data for Dyno Nobel, Inc., for 1994-2005, showing consistent use of selective catalytic control (SCR) emission control technology. Production data for 1990-1993 were not available.
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 2005 from the Nevada State Demographer's Office, University of Nevada, Reno, Nevada, "Nevada County Population Estimates July 1, 1990 to July 1, 2005, Includes Cities and Towns" (http://www.nsbdc.org/what/data_statistics/demographer/pubs/pdfs/NVpopul05.pdf). -- Population forecasts for 2006 to 2020 also from the Nevada State Demographer's Office, "Nevada County Population Projections 2006 to 2026" (http://www.nsbdc.org/what/data_statistics/demographer/pubs/docs/NV_2006_Projections.pdf). -- US 2000-2005 population from US Census Bureau (http://www.census.gov/population/projections/SummaryTabA1.xls).
Electric Power T&D Systems	1990 - 2002	Emissions from 1990 to 2003 based on the national emissions per kWh and state's electricity use.	National emissions per kWh from US EPA 2005 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003 (http://www.epa.gov/climatechange/emissions/usgginv_archive.html).

Table 5.2 Approach Used in Estimating Projected Emissions

Source Category	Time Period	Projection Assumptions	Data Source	Annual Growth Rates (%) 2000-2005	2005-2010	2010-2015	2015-2020
Cement Manufacturing - Clinker Production	2006-2020	Compound annual growth rate from Nevada's Nonmetallic Minerals sector employment projections (2004-2014). Assumed growth is same for 2015 – 2020 as in previous periods.	Nevada Department of Employment; (http://www.nevadaworkforce.com/cgi/dataanalysis/).	3.7	3.7	3.7	3.7
Lime Manufacture	2006-2020	Same as above	Same as above	3.7	3.7	3.7	3.7
Limestone and Dolomite Consumption	2003 - 2020	Same as above	Same as above	3.7	3.7	3.7	3.7
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.	Minerals Yearbook, 2005: Volume I, Soda Ash, (http://minerals.usgs.gov/minerals/pubs/commodity/soda_ash/soda_myb05.pdf).	0.5	0.5	0.5	0.5

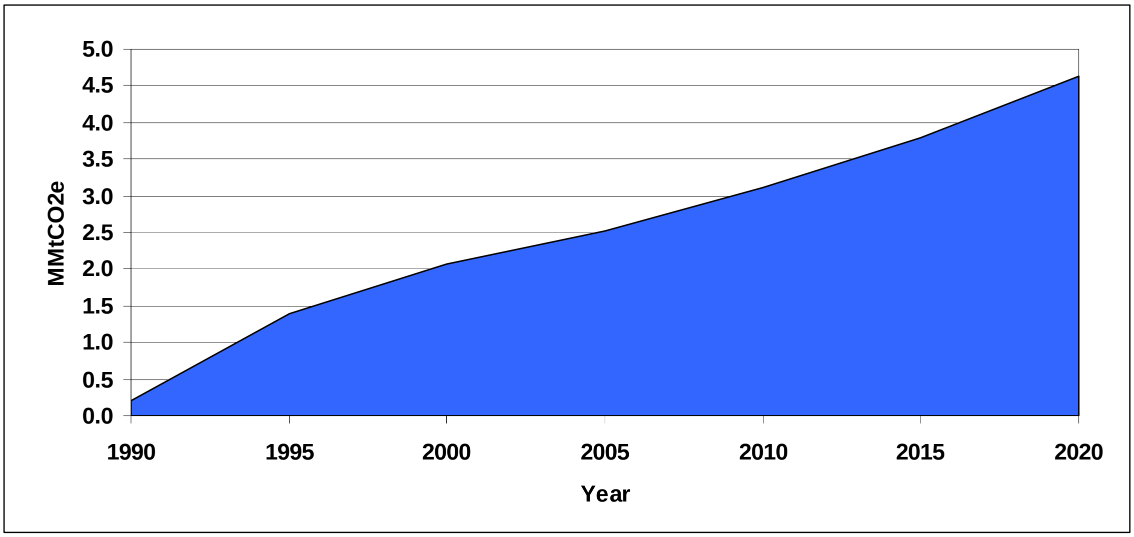
Table 5.2 Approach Used in Estimating Projected Emissions (Cont.)

Source Category	Time Period	Projection Assumptions	Data Source	Annual Growth Rates (%)			
				2000-2005	**2005-2010**	**2010-2015**	**2015-2020**
Nitric Acid Production	2006-2020	Compound annual growth rate from Nevada's Other Chemical Product and Preparation Manufacturing sector employment projections (2004-2014). Assumed growth is same for 2015 – 2020 as in previous periods.	Nevada Department of Employment; (http://www.nevadaworkforce.com/cgi/dataanalysis/).	-1.1	-1.1	-1.1	-1.1
ODS Substitutes	2003 - 2020	Based on national growth rate for use of ODS substitutes.	US EPA, 2004 ODS substitutes cost study report (http://www.epa.gov/ozone/snap/emissions/TMP6si9htnvca.htm).	15.8	7.9	5.8	5.3
Electric Power T&D Systems	2003 - 2020	National growth rate (based on aggregate for all stewardship program categories provided in referenced data source)	US Department of State, US Climate Action Report, 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

5.3 RESULTS

Table 5.3 and Figures 5.1 and 5.2 show historic and projected emissions for the industrial process sector from 1990 to 2020. Total sector GHG emissions were estimated at approximately 2.5 $MMtCO_2e$ in 2005 (4.5% of total emissions), rising to approximately 4.6 $MMtCO_2e$ in 2020 (5.9% of total emissions). Emissions from the overall industrial processes sector are expected to grow rapidly, as shown in Figures 5.1 and 5.2, with emissions nearly doubling from 2005 to 2020. The majority of historical and projected emissions are due to the use of HFCs and PFCs in refrigeration and air conditioning equipment, and, to a lesser extent, as a result of emissions of CO_2 associated with the production of lime and cement.

Figure 5.1 Total GHG Emissions from Industrial Processes, 1990-2020



HFCs and PFCs are used as substitutes for ODS, most notably chlorofluorocarbons (CFCs [CFCs are also potent warming gases]) in compliance with the *Montreal Protocol* and the *Clean Air Act Amendments of 1990*.[27] Even low amounts of HFC and PFC emissions, for example, from leaks and other releases associated with normal use of refrigeration equipment, can lead to high GHG emissions on a carbon-equivalent basis. Emissions increased from 0.0017 $MMtCO_2e$ in 1990 to about 0.54 $MMtCO_2e$ in 2000, and are expected to increase at an average rate of 6.2% per year from 2005 to 2020, for a total overall increase of 246%.

During the same period, CO_2 emissions from production of cement and lime are each projected to increase annually by 3.7%, due to demand growth in construction sector. CO_2 emissions from limestone and dolomite use increasing by 3.7% per year and CO_2 emissions from soda ash use increasing by 0.5% annually. Limestone, dolomite, and soda ash are the raw ingredients for a myriad of

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

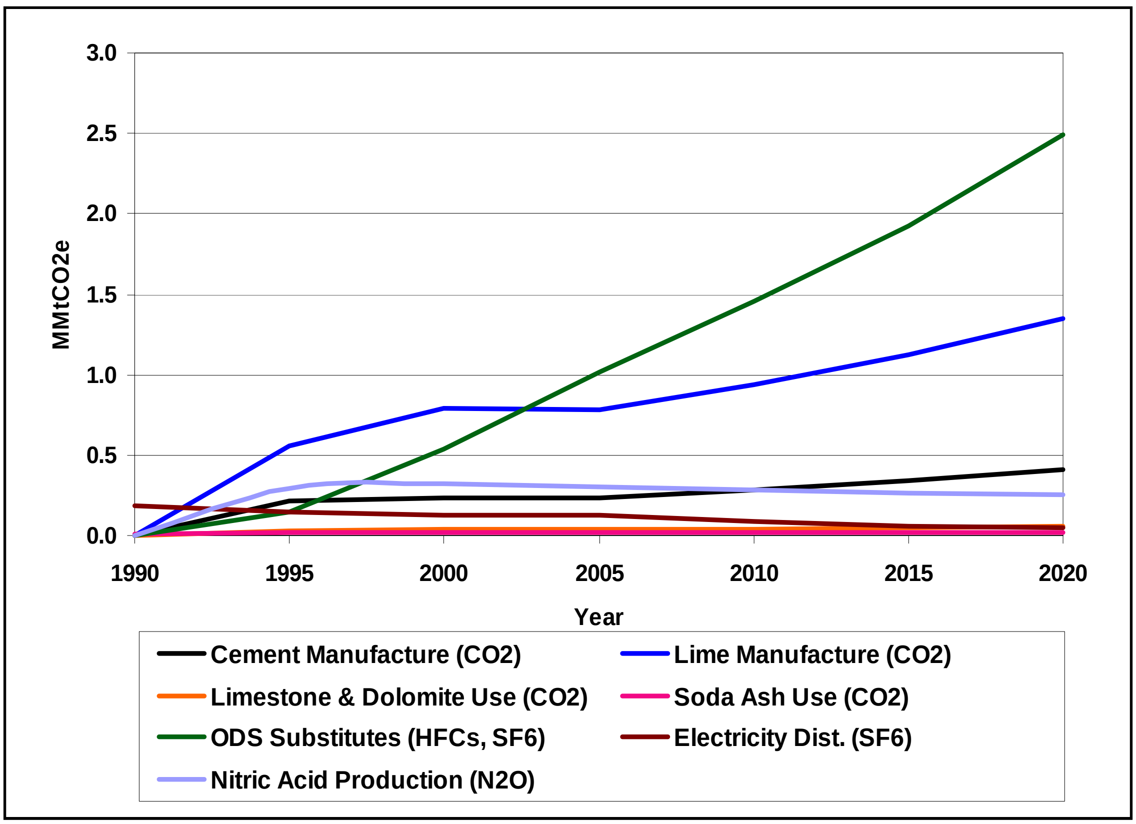
industries, from construction and agriculture, to the manufacture of consumer products such as glass, soap and detergents. N_2O and SF_6 emissions are both expected to decrease during the projection period, by approximately 1.2% and 5.8% per year, respectively. These emissions are produced in the manufacture of nitric acid (used as a component of synthetic commercial fertilizer, feedstock for nylon, and explosives), and from electricity transmission and distribution (where declines are mostly due to voluntary action by the industry), respectively.

Table 5.3 MMtCO2e Emissions from Industrial Processes, 1990-2020

Emission Source	1990	1995	2000	2005	2010	2015	2020
Cement Manufacture (CO2)	0.0	0.2	0.2	0.2	0.3	0.3	0.4
Lime Manufacture (CO2)	0.0	0.6	0.8	0.8	0.9	1.1	1.4
Limestone & Dolomite Use (CO2)	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Soda Ash Use (CO2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nitric Acid Production (N2O)	0.0	0.3	0.3	0.3	0.3	0.3	0.3
ODS Substitutes (HFCs, PFCs)	0.0	0.1	0.5	1.0	1.5	1.9	2.5
Electricity Dist. (SF_6)	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Total	0.2	1.4	2.1	2.5	3.1	3.8	4.6

Source: NDEP spreadsheet analysis

Figure 5.2 GHG Emissions from Industrial Processes, 1990-2020, by Source



5.4 UNCERTAINTIES

Since emissions from industrial processes are determined by both the level of production and the production processes of a few key industries, and, in some cases, of a few key plants, there is relatively high uncertainty regarding future emissions from the industrial processes sector as a whole. Future emissions depend on the competitiveness of Nevada manufacturers in these industries, and the specific nature of the production processes used in plants in Nevada.

The projected largest source of future industrial process emissions, HFCs and PFCs used in cooling applications, is subject to several uncertainties as well. First, historical emissions are based on national estimates; Nevada-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.

Historical clinker production data for Royal Cement in Clark County were not available. Consequently, historical emissions associated with cement production in Nevada are underestimated for 1990 through 2003. However, since this plant closed in 2004, the projections of future emissions were unaffected.

Production data for cement, lime, and nitric acid production and limestone and dolomite use were not available for 1990 through 1993, and were assumed to be lower than current levels. Consequently, emissions from these years were not added to the total emissions for the industrial non-energy process sector, potentially leading to underestimated emissions for these three years. If the production (or consumption) levels for these industries in 1990 are assumed to match the 1994 production (or consumption) levels, the 1990 emissions would be approximately 0.7 $MMtCO_2e$.

6.0 FOSSIL FUEL INDUSTRY SECTOR EMISSIONS

6.1 OVERVIEW

This section reports GHG emissions that are released during the production, processing, transmission, and distribution of fossil fuels in the state. Known primarily as fugitive emissions, these are methane (CH_4) and carbon dioxide (CO_2) emissions released via leakage and venting from oil and gas fields, processing facilities, and pipelines. Emissions associated with energy consumed by these processes are included in Section 3, Residential, Commercial and Industrial Sector.

Nevada's oil and gas industry is small and has declined to very low levels in recent years. Current crude oil production across the entire State is only about 1,000 barrels per day, which ranks Nevada 27th out of 31 producing states.[28] Nevada's proven crude oil reserves account for less than 1% of the US total. Oil production in Nevada peaked in 1990 at 11,000 barrels per day, and has been declining steadily ever since.[29] Nevada has one petroleum refinery with a crude oil distillation capacity of 2,000 barrels per day.[30]

Nevada's marketed natural gas production peaked in 1991 at 53 MMcf and has steadily decreased since that time, to about 5 MMcf in 2004.[31] In comparison, Nevada consumed over 200,000 MMcf of natural gas in 2004, and consumption has grown an average of 7% per year since the year 2000.[32] Since Nevada has no additional known reserves of natural gas (conventional or coal bed CH_4), Nevada will likely continue to rely almost entirely on imports of natural gas.[33] There is no coal bed CH_4 production or proven reserves in Nevada.[34]

Nevada's fossil fuel industry is the smallest source of statewide GHG emissions. Total sector emissions were estimated at approximately 0.8 $MMtCO_2e$ in 2005 and are projected to reach approximately 0.9 $MMtCO_2e$ in 2020. These totals represent approximately 1.4% of statewide GHG emissions in 2005 and 1.1% in 2020. The projected increase in sector emissions is primarily the result of the projected addition of natural gas distribution pipeline infrastructure in Nevada to serve the RCI sector.

Approximately 84% of sector emissions in 2005 are estimated to have occurred as a result of fugitive CH_4 emissions, released primarily via leakage and venting from the state's estimated 9,000 miles of gas

28 "Petroleum Profile: Nevada", US DOE Energy Information Administration website, October 2006, Accessed at http://tonto.eia.doe.gov/oog/info/state/nv.html.
29 "Petroleum Navigator", US DOE Energy Information Administration website, October 2006, Accessed at http://tonto.eia.doe.gov/dnav/pet/hist/mcrfpnv2a.htm.
30 "Petroleum Profile: Nevada", US DOE Energy Information Administration website, October 2006, Accessed at http://tonto.eia.doe.gov/oog/info/state/nv.html.
31 "Natural Gas Navigator", US DOE Energy Information Administration website, December 2006, Accessed at http://tonto.eia.doe.gov/dnav/ng/hist/na1140_snv_2a.htm.
32 "Natural Gas Navigator", US DOE Energy Information Administration website, November, 2006, Accessed at http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SNV_a.htm.
33 "Nevada Energy Status Report 2005" Nevada State Office of Energy, Accessed at http://energy.state.nv.us/2005%20Report/Final%20CD/Chapter%203%20-%20Final.doc.
34 "Natural Gas Navigator", US DOE Energy Information Administration website, December 2006.

pipelines.[35] All, but 0.05% of the remainder of sector emissions in that year, were associated with CO_2 and N_2O emissions from the combustion of natural gas used to power pipeline compressor stations.

6.2 METHODOLOGY

The SIT was used to estimate historic greenhouse gas emissions.[36] 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 state-wide activity data are the US DOE EIA[37] and American Gas Association's annual publication *Gas Facts*.[38] Methane emissions were estimated using SIT, with reference to the EIIP guidance document.

Projected estimates of CH_4 emissions from the state's oil and gas systems are derived from both the forecasted rate of expansion of the natural gas transmission and distribution pipeline network and, the forecasted decline in oil and gas production. Because there are no confirmed plans to expand the length of gas transmission pipelines in Nevada, the only increase in fugitive CH_4 would result from additional gas distribution pipeline needed to serve the RCI sector. Therefore, the forecasted increase in annual state population growth during the period of 2006-2020, 2.19%, was used to project the increase in distribution pipeline emissions.[39]

On the other hand, oil and natural gas production are expected to continue to decline, as they have been for more than a decade in Nevada. Oil and gas production emission rate projections were calculated based on their 2001 to 2006 rate averages; while, oil refining and oil transport, were assumed to remain flat at less than 0.005MMtCO2e/year. Decreases in natural gas production were not assumed to affect use of transmission infrastructure over the near-term, thus transmission sector emissions rates were held constant at 2004 levels.

Natural gas pipeline fuel compression represents the CO_2 emissions created from the combustion of natural gas in reciprocating engines used to compress and transport gas through high-pressure transmission pipelines. Historic emissions associated with gas compression were based on EIA fuel consumption data for the period of 1990-2005. Since there are no confirmed plans to expand the length of gas transmission pipeline in Nevada, emissions associated with this emission activity were held constant at the 2004 level.

Table 6.1 provides an overview of data sources and the approach used for estimating historical emissions and projecting future emissions.

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35 Data from EIA and the American Gas Association's *Gas Facts*.

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

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

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

39 Population forecasts for 2006 to 2020 from the Nevada State Demographer's Office, University of Nevada, Reno, Nevada, "Nevada County Population Projections 2008 to 2028" (http://www.nsbdc.org/what/data_statistics/demographer/pubs/docs/NV_Projections_2008_Report.pdf).

Table 6.1 Approach to Estimating Historical and Projected Emissions from Natural Gas and Oil Systems

	Approach to Estimating Historical Emissions		Approach to Estimating Projections
Activity	***Required Data for SIT***	***Data Source***	***Projection Assumptions***
Natural Gas Drilling and Field Production	Number of wells	EIA	Emission projections assume that natural gas production will continue to decline at 8.4% annually until 2020.[40]
	Miles of gathering pipeline	*Gas Facts*[41]	
Natural Gas Processing	Number gas processing plants	EIA[42]	There is no natural gas processing in the state of Nevada.
Natural Gas Transmission	Miles of transmission pipeline	*Gas Facts*	Emissions are held flat at 2004 levels. Emissions levels would increase with the expansion of transmission infrastructure.
	Number of gas transmission compressor stations	EIIP[43]	
	Number of gas storage compressor stations	EIIP[44]	
	Number of LNG storage compressor stations	Paiute Pipeline Company[45]	
Natural Gas Distribution	Miles of distribution pipeline	*Gas Facts*	Distribution emissions follow State gas consumption trend - annual average growth rate based on projected RCI sector consumption.
	Total number of services[46]	*Gas Facts*	
	Number of unprotected steel services[47]	Ratio estimated from 2002 data	
	Number of protected steel services[48]	Ratio estimated from 2002 data	

40 Nevada natural gas production declined at an average annual rate of 8.4% between 2000 and 2004, as reported by the EIA. Production has been declining since first reported by the EIA in 1991.

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

42 EIA reports no gas processing facilities in Nevada.

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

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

45 Paiute Pipeline Co. owns the only LNG storage facility in NV, which was placed into service in 1982. Per phone conversation with Jeff Maples, Director gas operations. Reference http://www.paiutepipeline.com/ and http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/lng/lng2003.pdf.

46 Total number of services refers to the number of gas customer connections

47 Gas Facts reported unprotected and protected steel services for 2002, but only total services for other years. Therefore the ratio of unprotected and protected steel services in 2002 was assumed to be the ratio for all other years (0.4891 for protected services and 0.0045 for unprotected services). This yields more congruent results than the EIIP guidance of using multipliers of 0.2841 for protected steel services, and 0.0879 for unprotected steel services.

48 Ibid.

Table 6.1 Approach to Estimating Historical and Projected Emissions from Natural Gas and Oil Systems (Cont.)

	Approach to Estimating Historical Emissions		Approach to Estimating Projections
Activity	***Required Data for SIT***	***Data Source***	***Projection Assumptions***
Natural Gas Pipeline Fuel Compression	Billion Btu of natural gas consumed	EIA SEDS	Emissions are held constant at 2004 levels. Emission levels would increase with the expansion of transmission infrastructure.
Oil Production	Annual production	EIA[49]	Emissions follow a State oil production trend, which continues to decline at 6.3% annually.[50]
Oil Refining	Annual amount refined	EIA[51]	Emissions are projected to hold flat at 2004 levels.[52]
Oil Transport	Annual oil transported	Unavailable, assumed oil refined = oil transported	Emissions are projected to hold flat at 2004 levels.

6.3 RESULTS

Table 6.2 shows the estimated fossil fuel industry sector GHG emissions in Nevada from 1990 to 2005, with projections to 2020. Emissions from this sector grew by approximately 83% from 1990 to 2005 and are projected to increase by approximately 36% from 2005 to 2020. Natural gas transmission and distribution systems are the major contributors to historic fugitive GHG emissions, with natural gas distribution driving future emissions growth for this sector. Figure 6.1 graphs the trend in sector emission categories over the time period of 1990 to 2020.

Table 6.2 Historical and Projected Fossil Fuel Industry GHG Emissions ($MMtCO_2e$)

Emission Source	1990	1995	2000	2005	2010	2015	2020
Oil - Production & Refining	0.03	0.01	0.01	0.00	0.00	0.00	0.00
Nat. Gas - Transmission	0.22	0.24	0.26	0.31	0.31	0.31	0.31
Nat. Gas - Distribution	0.13	0.18	0.25	0.33	0.41	0.50	0.57
Nat. Gas - Pipeline Fuel	0.04	0.04	0.05	0.12	0.15	0.16	0.16
Total	0.42	0.47	0.57	0.77	0.88	0.98	1.05

Note: Emissions less than 0.005 MMtCO2e are shown as 0.00 in the above table.

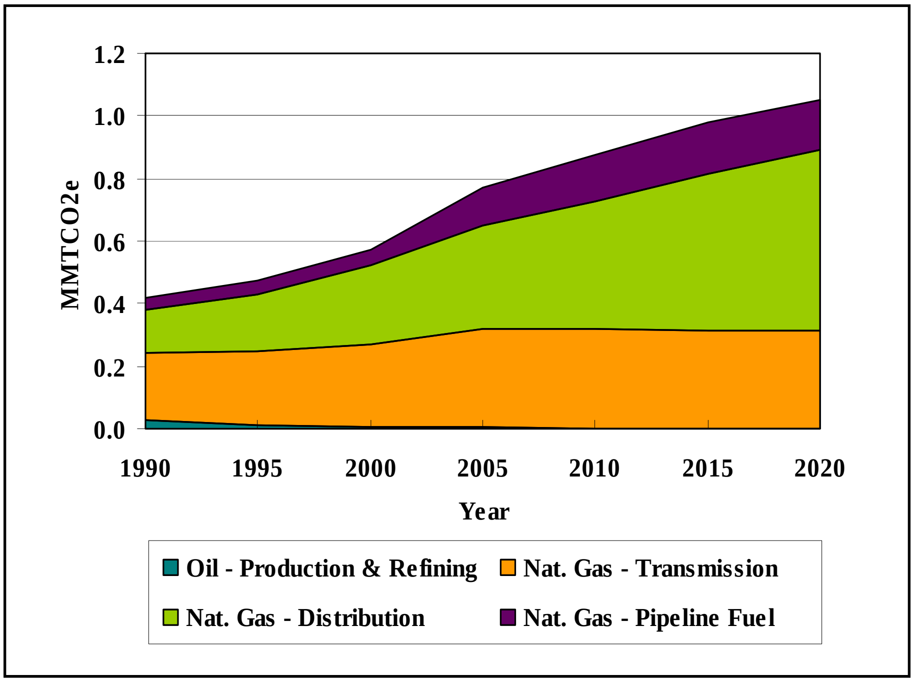
49 Data extracted from the Petroleum Supply Annual for each year.

50 Oil production has been declining since the early 1990's. Average annual decline rate between 2001 and 2005 was 6.3%.

51 Refining assumed to be equal to the total input of crude oil into PADD V times the ratio of Nevada's refining capacity to PADD V's total refining capacity. No data for 1995 and 1997, so linear relationship assumed from previous and subsequent years.

52 There is currently only one operating refinery in Nevada.

Figure 6.1 Fossil Fuel Industry GHG Emission Trends



6.4 UNCERTAINTIES

Due to the lack of emissions data specific to Nevada's oil and gas infrastructure, historic fugitive emission levels are estimated based upon nationwide industry averages which may, or may not, be representative of actual emissions.

Large uncertainty exists regarding the historic ratio of the length of unprotected, versus protected, steel gas distribution pipeline. Historical emissions associated with fugitive emissions from natural gas distribution pipeline were based on only one year of data (2002) as reported by *Gas Facts.* Alternative sources of data concerning type and length of distribution pipeline constructed throughout the state should be researched in the attempt to improve the integrity of historical and projected emissions estimates.

Projections of future sector emissions are difficult to forecast given the mix of economic factors that affect sector activity as driven by future oil and gas demand. The assumptions used for the projections, extending historical decline or growth trends out to 2020, do not include any significant real changes in energy prices. Large price fluctuations, supply limitations, or changes in pollution control regulations could significantly change future oil and gas production and the associated GHG emissions. Other uncertainties include the development of future natural gas transmission pipelines through Nevada, and potential emission reduction improvements to production, processing, and pipeline technologies.

7.0 AGRICULTURE SECTOR EMISSIONS

7.1 OVERVIEW

The emissions discussed in this section refer to non-energy methane (CH_4) and nitrous oxide (N_2O) emissions from enteric fermentation, manure management, and agricultural soils. Emissions and sinks of carbon in agricultural soils are also covered. Energy emissions (combustion of fossil fuels in agricultural equipment) are not included in this section, but are incorporated into the RCI sector estimates.

Nevada's agriculture industry is a minor source of GHG emissions. Total sector emissions were estimated at approximately 1.6 $MMtCO_2e$ in 2005 and are projected to reach approximately 1.8 $MMtCO_2e$ in 2020. These totals represent approximately 2.9% of statewide GHG emissions in 2005 and only 2.3% in 2020. The projected increase in sector emissions is primarily the result of emissions from the projected increase in manure management at livestock operations (including dairies).

There are two livestock sources of 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 animal digestive systems breakdown food and emit CH_4 as a by-product. More CH_4 is produced in ruminant livestock because of digestive activity in the large fore-stomach. Methane and N_2O emissions from the storage and treatment of livestock manure occur as a result of manure decomposition (e.g., in compost piles or anaerobic treatment lagoons). The environmental conditions of decomposition drive the relative magnitude of emissions. In general, the more anaerobic the conditions are, the more CH_4 is produced because decomposition is aided by CH_4 producing bacteria that thrive in oxygen-limited aerobic conditions. Under aerobic conditions, N_2O emissions are dominant. Emissions estimates from manure management are based on manure that is stored and treated on livestock operations. Emissions from manure that is applied to agricultural soils as an amendment or deposited directly to pasture and grazing land by grazing animals are accounted for in manure fertilizer emissions.

The management of agricultural soils can result in N_2O emissions and net fluxes of CO_2 creating either emissions or sinks. In general, soil amendments that add nitrogen to soils can also result in N_2O emissions. Nitrogen additions drive underlying soil nitrification and de-nitrification cycles, which produce N_2O as a by-product. The emissions estimation methodologies used in this inventory account for several sources of N_2O emissions from agricultural soils, including decomposition of crop residues, synthetic and organic fertilizer application, manure application, sewage sludge, nitrogen fixation, and histosols (high organic soils, such as wetlands or peatlands) cultivation. Both direct and indirect emissions of N_2O 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 N_2O emissions also result when crop residues are burned.

The net flux of CO_2 in agricultural soils depends on the balance of carbon losses from management practices and gains from organic matter inputs to the soil. Carbon dioxide is absorbed by plants through photosynthesis and ultimately becomes the carbon source for organic matter inputs to agricultural soils. When inputs are greater than losses, the soil accumulates carbon and there is a net sink of CO_2 into agricultural soils. In addition, soil disturbance from the cultivation of histosols releases large stores of carbon from the soil to the atmosphere. Finally, the practice of adding limestone and dolomite to agricultural soils results in CO_2 emissions.

7.2 METHODOLOGY

Methane and Nitrous Oxide

GHG emissions for 1990 through 2005 were estimated using SIT and the methods provided in the Emission Inventory Improvement Program (EIIP) guidance document for the sector.[53] In general, the SIT methodology applies emission factors developed for the US to activity data from 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.[54]

Data on crop production in Nevada from 1990 to 2005 and the number of animals in the state from 1990 to 2002 were obtained from the USDA National Agriculture Statistical Service (NASS) and incorporated as defaults into the SIT.[55] The default SIT manure management system assumptions for each livestock category were used for this inventory. Data on fertilizer usage for 1990 through 1999 is based on the data provided for Nevada in the SIT.[56] The Nevada Department of Agriculture provided data for fertilizers containing nitrogen for 2003 through 2005, confirmed the accuracy of the historical SIT data for 1990 through 1999, and provided slight revisions to the SIT data for 2000 through 2002.[57] Activity data for fertilizer includes all potential uses in addition to agriculture, such as residential and commercial (for example, golf courses). The estimates are reported in the Agriculture sector but they represent emissions occurring on other land uses.

Crop production data from USDA NASS were available through 2005; therefore, N_2O emissions from crop residues and crops that use nitrogen (i.e., nitrogen fixation) and CH_4 emissions from agricultural residue burning were calculated through 2005. Data for the other agricultural crop production categories (i.e., synthetic and organic fertilizers) were only available through 2002, so historical emissions estimates were confined to 1990-2002.

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

[54] Revised 1996 1ntergovermental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, published by the National Greenhouse Gas Inventory Program of the IPCC, available at (http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm; and Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, published in 2000 by the National Greenhouse Gas Inventory Program of the IPCC, available at: (http://www.ipcc-nggip.iges.or.jp/public/gp/english/).

[55] USDA, NASS (http://www.nass.usda.gov/Statistics_by_State/Nevada/index.asp).

[56] The Association of American Plant Food Control Officials and The Fertilizer Institute. 2002. Commercial Fertilizers. "Table 9 - Consumption of Primary Plant Nutrients. Total Nutrients-All Fertilizers (N)." Data based on "growing year" (i.e., data are reported for the last six months of one year starting July 1, and the first six months of the following year ending June 30).

[57] Data provided by Dr. Chris Mason, Nevada Department of Agriculture, Plant Industry Division on December 15, 2006.

There is some agricultural residue burning conducted in Nevada. The SIT methodology calculates emissions by multiplying the amount (e.g., bushels or tons) of each crop produced by a series of emission factors to calculate the amount of crop residue produced and burned, the resultant dry matter, and the carbon/nitrogen content of the dry matter**.** However, the default SIT method was used to calculate emissions because activity data in the form used in the SIT were not readily available.

Emissions from crop residues, crop burning, and nitrogen fixing crops were projected based on the annual growth rate in historical emissions ($MMtCO_2e$ basis) for these categories in Nevada for 1990 to 2005. Emissions projections from enteric fermentation, manure management, and agricultural soils (except fertilizers) were limited to 1990 to 2002 data. Table 7.1 shows the annual growth rates applied to estimate the reference case projections by emission source. The compound annual growth rate for historic fertilizer (containing nitrogen) usage in Nevada was about 6.6% from 1990 to 2005. In recent years, the annual growth rate declines to -3.7% from 2000 through 2005.

According to the Nevada Department of Agriculture, fertilizer usage increased significantly from 1990 to 2000 due to the growth in the residential and commercial sectors over this time period in Nevada's urban areas. For example, many golf courses were built thus increasing the demand for fertilizer. Since 2000 fertilizer usage has declined due to the slowing in economic growth and because higher energy prices for producing fertilizer resulted in increased fertilizer prices. Without any other data, population growth is expected to be the best indicator of growth in fertilizer use, particularly in the residential and commercial sectors. However, higher fertilizer costs and other economic factors could impact fertilizer use just as they did during the historical period from 2000-2005. Therefore, the growth rate for fertilizers is based on the population growth rate for Nevada.[58,59]

Table 7.1 Growth Rates Used to Project Agricultural Sector Emissions by Source

Emissions Source	Projected Annual Growth Rate	Basis for Projected Annual Growth Rate[a]
Animal Sources:		
Enteric Fermentation	0.3%	Historical emissions for 1990-2002.[a]
Manure Management	2.3%	Historical emissions for 1990-2002.[a]
Crop Sources:		
Ag. Residue Burning	0.0%	Assumed no growth.
Nitrogen-based Fertilizers	2.1% - 4.3%	Based on Nevada's population growth.[b]
Crop Residues	-3.3%	Historical emissions for 1990-2005.[a]
Nitrogen-Fixing Crops (NFC)	1.6%	Historical emissions for 1990-2005.[a]
Manure Fertilizer	-0.17%	Historical emissions for 1990-2002.[a]
Indirect Sources:		
Fertilizer Leaching/Runoff	2.1% - 4.3%	Based on Nevada's population growth.[b]

[a] Compound annual growth rate was calculated using the growth rate in historical emissions ($MMtCO_2e$ basis) from 1990 through the most recent year of data. These growth rates were applied to forecast emissions from the latest year of data to 2020.

58 Dr. Chris Mason, Nevada Department of Agriculture, Plant Industry Division. Personal communication, December 15, 2006.

59 Population forecasts for 2006 to 2020 from the Nevada State Demographer's Office, University of Nevada, Reno, Nevada, "Nevada County Population Projections 2006 to 2026" (http://www.nsbdc.org/what/data_statistics/demographer/pubs/docs/NV_2006_Projections.pdf).

[b] The human population annual growth rates applied are as follows: 4.2% for 2005 to 2010, 3.2% for 2010 to 2015, and 2.1% for 2015 to 2020.

Data were not available to estimate nitrogen released by the cultivation of histosols (including data such as the number of acres of high organic content soils). However, as discussed in the following section for soil carbon, the Natural Resources Ecology Laboratory at Colorado State University estimated zero CO_2 emissions for organic soils in Nevada for 1997, suggesting that the area of cultivated high organic content soils was either very small or zero in Nevada. Therefore, N_2O emissions from cultivated histosol soils were also assumed to be zero.

Agricultural Soils

Net soil 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*[60] 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 Unite States. Preliminary state-level estimates of CO_2 fluxes from mineral soils and emissions from the cultivation of organic soils were reported in the *U.S. Agriculture and Forestry Greenhouse Gas Inventory*. Currently, these are the best available data at the state-level for this category. However, the inventory did not report state-level estimates of CO_2 emissions from limestone and dolomite applications; hence, this source can not be 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; additions of manure; participation in the Federal Conservation Reserve Program (CRP); and cultivation of organic soils (with high organic carbon levels). Data on changes in agricultural practices are only available for one year (1997). Despite this small sample size, these data were used to create a baseline estimate for the net statewide agricultural soils carbon sink of 0.18 $MMtCO_2e$/yr. Since data from other years are not yet available from USDA to make a determination of whether the emissions are increasing or decreasing, the net sink of 0.18 $MMtCO_2e$/yr is assumed to remain constant.

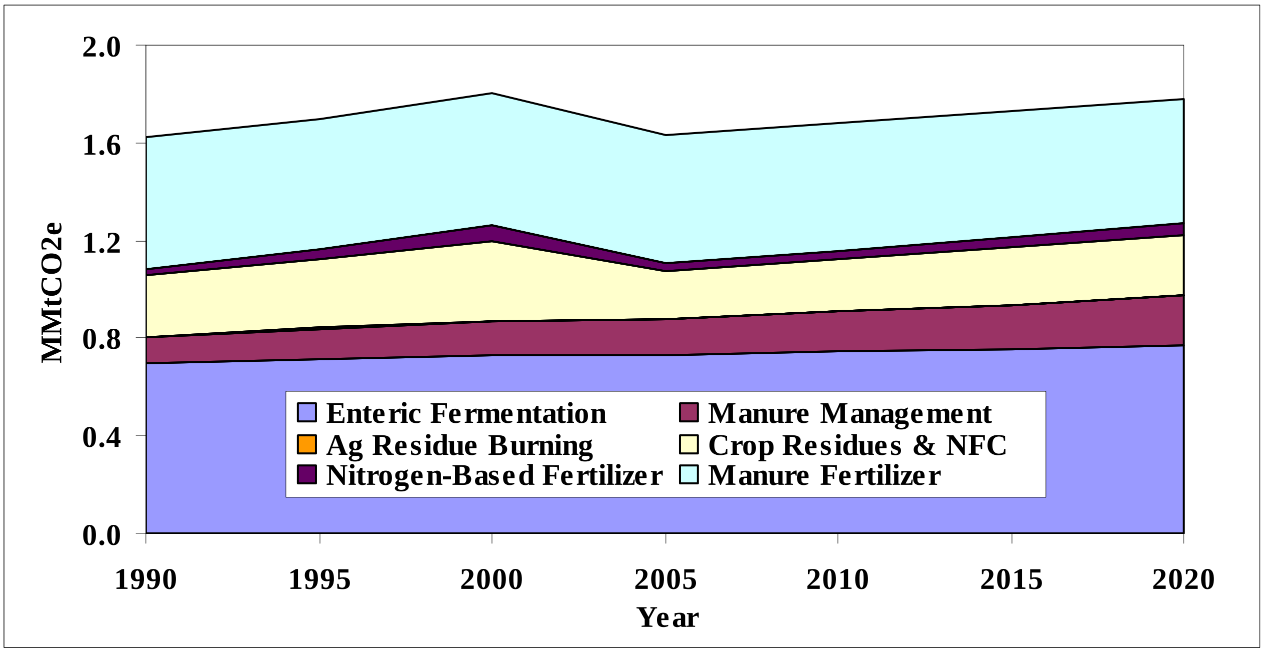
7.3 RESULTS

As shown in Figure 7.1, gross emissions from agricultural sources range between about 1.6 and 1.8 $MMtCO_2e$ from 1990 through 2020, respectively. In 1990, enteric fermentation accounted for about 43% (0.70 $MMtCO_2e$) of total agricultural emissions and is estimated to account for the same proportion 43% (0.77 $MMtCO_2e$) in 2020. The manure management source category, which shows the highest rate of growth relative to the other categories from 1990-2020, accounted for 6.5% (0.11 $MMtCO_2e$) of total agricultural emissions in 1990 and is estimated to account for about 11.5% (0.21 $MMtCO_2e$) of total agricultural emissions in 2020. Including the CO_2 sequestration from soil carbon changes, the historic and projected emissions for the agriculture sector would range between about 1.4 and 1.6 $MMtCO_2e$/yr.

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

Agricultural burning emissions were estimated to be very small based on the SIT activity data (<0.0001 $MMtCO_2e$/yr from 1990 to 2002). This agrees with the USDA Inventory which also reports a low level of residue burning emissions (0.02 $MMtCO_2e$).

Figure 7.1 Gross GHG Emissions from Agriculture



Notes: Emissions for agricultural residue burning are too small to be seen in this figure. Soil carbon sequestration is not shown.

7.4 UNCERTAINTIES

Emissions from enteric fermentation and manure management are dependent on the estimates of animal populations and the various factors used to estimate emissions for each animal type and manure management system (i.e., emission factors which are derived from several variables including manure production levels, volatile solids content, and CH_4 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 and therefore may not represent current conditions and recent trends. In particular, given the potential for some Conservation Reserve Program (CRP) acreage to retire and possibly return to active cultivation prior to 2020, the current size of the CO_2 sink could be appreciably affected.

Emission estimates for soil liming have not been developed for Nevada and so could not be included.

8.0 WASTE MANAGEMENT SECTOR EMISSIONS

8.1 OVERVIEW

Nevada's waste management GHG emissions occur from two source categories: 1) solid waste management, mainly in the form of CH_4 emissions from municipal and industrial solid waste landfills (including CH_4 that is flared or captured for energy production); and 2) wastewater management, including CH_4 and N_2O from municipal and industrial wastewater (WW) treatment facilities.

Nevada's waste management sector is a minor source of statewide GHG emissions. Total sector emissions were estimated at approximately 1.4 $MMtCO_2e$ in 2005 and are projected to reach approximately 2.2 $MMtCO_2e$ in 2020. These totals represent approximately 2.4% of statewide GHG emissions in 2005 and 2.7% in 2020. The projected increase in sector emissions is primarily the result of the projected increase in landfill gas emissions as driven by projected population growth. Population growth is also the driver for the increase in wastewater management emissions.

8.2 METHODOLOGY

Solid Waste Management

US EPA's SIT and Landfill Methane Outreach Program (LMOP) landfills database[61] were used as starting points to estimate historical emissions. The LMOP database provided annual waste emplacement estimates for the ten largest landfills in the state, representing almost all of total statewide emplacement.[62] These estimated waste volumes were used in the SIT to estimate CH_4 generation for each landfill site. The SIT estimates are then modified to include the reduction in CH_4 landfill emissions from state-mandated control measures. Intended to reduce the explosion hazard posed by CH_4 seeping from landfills, the regulations require landfill operators to monitor and reduce CH_4 below predetermined levels. Additional state-specific information on emplacement rates for both municipal solid waste (MSW) and industrial waste from the NDEP's Bureau of Waste Management (BWM) solid waste staff was used to fill data gaps in the LMOP data. In addition, contacts at the health departments in Washoe and Clark County provided additional information on the current and future application of controls at the State's three largest landfills (Lockwood, Sunrise, and Apex).[63]

To obtain the annual disposal rates needed by SIT for each landfill, the volume of waste-in-place was divided by the number of years of operation. For most cases, this average annual disposal rate was assumed for all years that the landfill was operating. However, a few landfills in the state have experienced dramatic growth in recent years. In cases where the current (2005) disposal rate reported to NDEP was significantly higher than the average annual disposal rate, the estimated disposal rate for recent years were adjusted to reflect this change.

[61] 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, personal communication, October 2006.

[62] State of Nevada, Solid Waste Management Plan, 2007.

[63] Jeannie Rucker, Washoe County Department of Health and Dennis Campbell, Clark County Department of Health, Personal communication, December 2006. In Washoe County, the Lockwood LF will likely need to install controls by 2010. These controls have not been included in the emissions forecast.

With these emplacement rate estimates, three different SIT analysis runs were performed to estimate emissions from MSW landfills: 1) uncontrolled landfills; 2) landfills with a landfill gas collection system and LFGTE plant (Apex – LFG collection and flare from December, 2000 to present, LFGTE to be installed by 2010[64]); and, 3) landfills with a landfill gas collection system and flare (Sunrise – LFG collection and flare from November, 2002 to present). Lockwood was modeled with the other uncontrolled sites (future year emissions were adjusted by assuming a flare is installed in 2010). SIT produced annual estimates through 2005 for each of these landfill categories. Some post-processing of the landfill emissions was then performed to account for landfill gas controls (at LFGTE and flared sites) and to project the emissions through 2020. For the controlled landfills, methane control efficiency was assumed to remain constant at current levels (75%) throughout the projection period.[65] Sunrise site waste emplacement rates, based on available LMOP data, were estimated to be an average of 1 million tons/year from 1960-1993, and zero from 1993-present. This is also the annual mass of waste that the Apex landfill began accepting when it opened to replace the Sunrise site. For the Lockwood site, Washoe County indicated that a flare would probably be installed within the next year, and emissions are projected to drop by a significant amount.

The SIT was used (with slight modification) to create emissions estimates for industrial landfills as well. The SIT default is based on national data indicating that industrial landfills generate methane at approximately 7% of the rate of MSW landfills. In Nevada, however, there is a significant amount of industrial and special wastes (such as asbestos, medical waste, and waste tires) emplaced in the State's landfills, far exceeding the national average of 7%. Based on summary data provided by the BWM, the amount of industrial waste emplaced in 2005 was nearly equal to the amount of MSW; industrial emplacement rates over the survey period also matched those of MSW emplacement. Given that a large fraction of industrial/special wastes is likely to be non-degradable, it was assumed that landfill gas generation from industrial waste emplacement is 50% of the MSW generation rate. A large fraction of this waste is emplaced at the Apex and Lockwood landfills; however, it is not clear whether this waste would be flared along with the MSW at Apex (and at Lockwood in the future). Therefore, no controls were assumed for industrial waste.

For the uncontrolled landfills, industrial LFs, flared LFs, and LFGTE operations, emission growth rates were extrapolated from historical waste emplacement volumes in each category. The annual growth rate for uncontrolled landfills is 2.9%.[66] This growth rate is consistent with the State's rapid population growth from 1990-2005 (4.9%/yr), although waste imports from neighboring states added up to 10% to the growth in waste emplacement. The projected emissions from industrial landfills are 4.5%/yr, based on the average overall growth rate in MSW emissions from 1990 to 2005. For flared landfills (the Sunrise LF), the SIT calculations produced an emissions reduction rate of -3.4%/yr, based on data from 1992-1999. This rate estimate excludes the effect of CH_4 emissions controls adopted in 2007, as the flare reduces amount of emissions, but not the rate of emissions reduction (the installation of emissions controls can be observed in the dramatic drop in flared LF emissions in 2007 in Figure 8.1). Historical

[64] Alan Gaddy, Republic Services. Personal communication, November 13, 2008

[65] As per EPA's AP-42 Section on Municipal Solid Waste Landfills: http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf. However, of the 25% of methane not captured by a landfill gas collection system, it is assumed that 10% is oxidized before being emitted to the atmosphere (consistent with the SIT default).

[66] The growth rate reflects a doubling of the emplacement rate between 1993 and 2005.

emplacement growth estimates for Nevada's LFGTE facility (Apex) is 5.6%/yr, which is consistent with the state's population growth rate. This growth rate was assumed to remain constant during the projection period, as no data were available to determine the effects on emissions of transitioning from current controls (based on flaring) to future controls, including LFGTE.

Wastewater Management

The estimation of GHG emissions from municipal wastewater treatment were calculated using SIT based on state population, assumed biochemical oxygen demand (BOD), and emission factors for N_2O and CH_4. The key SIT default values are shown in Table 8.1.

Table 8.1 SIT Key Default Values for Municipal Wastewater Treatment

Variable	Value
BOD	0.065 kg /day-person
Amount of BOD anaerobically treated	16.25%
CH_4 emission factor	0.6 kg/kg BOD
Nevada residents not on septic	75%
Water treatment N_2O emission factor	4.0 g N_2O/person-yr
Biosolids emission factor	0.01 kg N_2O-N/kg sewage-N

For industrial wastewater emissions, SIT provides default assumptions and emission factors for three industrial sectors: Fruits & Vegetables, Red Meat & Poultry, and Pulp & Paper. However, there are no pulp and paper operations in the State, and no data were identified regarding the operation of fruit & vegetable or meat & poultry plants in Nevada. According to Dunn & Bradstreet (a business information reporting company), there were no significant operations in any of the above industrial categories as of 2002.[67] Therefore, emissions from the industrial wastewater treatment sector are considered to be negligible.

8.3 RESULTS

Table 8.2 and Figure 8.1 show the total emission estimates for the waste management sector broken down by type. Overall, the sector accounted for 0.8 $MMtCO_2e$ in 1990 and 1.4 $MMtCO_2e$ in 2005. By 2020 aggregate emissions are expected to grow to 2.2 $MMtCO_2e$ per year. In 2005, approximately 36% of the emissions (the majority of sector emissions) were contributed by uncontrolled landfills, with this contribution percentage maintained through 2020. The emissions contribution of the LFGTE sector (the Apex facility) is 19% in 2005, growing to 27% by 2020. Emissions from the flared Sunrise landfill decrease from 0.2 $MMtCO_2e$ in 2005 to 0.02MMt/yr by 2020.

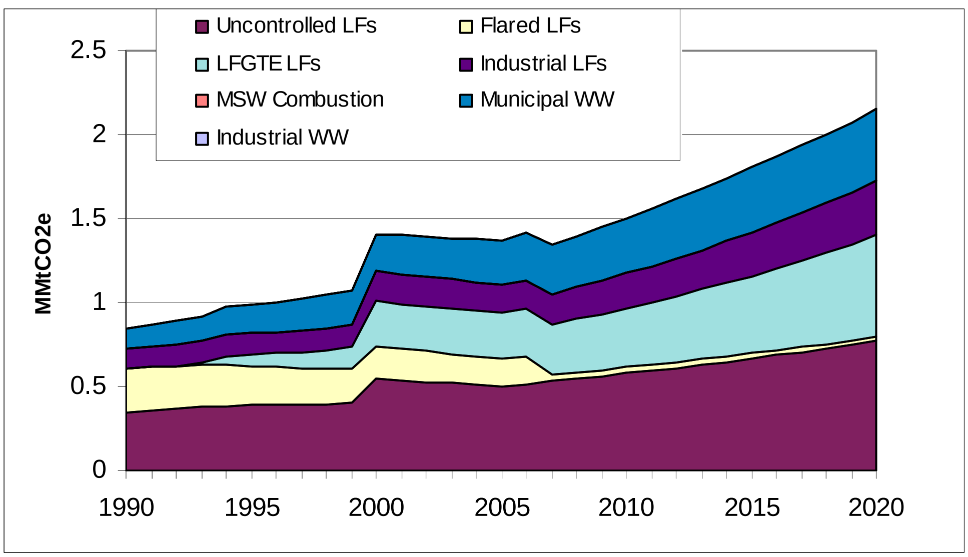
Emissions from municipal wastewater treatment were estimated to be 0.13 $MMtCO_2e$ in 1990 and 0.27 $MMtCO_2e$ in 2005, with the latter amount representing approximately 19.6% of the waste management sector emissions total in 2005. Roughly the same percentage is forecast through 2020, with municipal wastewater emissions reaching 0.428 $MMtCO_2e$/yr.

[67] Dun & Bradstreet, *MarketPlace CD*, Jan-Mar 2002. The data include some business operations in the Standard Industrial Classification codes for the industries of interest; however the number of employees is too small to indicate significant industrial operations.

Table 8.2 Waste Management Sector Emissions (MMtCO2e), 1990-2020

Emission Source:	1990	1995	2000	2005	2010	2015	2020
Uncontrolled LFs	0.35	0.39	0.54	0.50	0.58	0.67	0.77
Flared LFs	0.26	0.23	0.20	0.16	0.03	0.03	0.02
LFGTE LFs	0.00	0.07	0.27	0.27	0.35	0.46	0.61
Industrial LFs	0.12	0.13	0.18	0.17	0.21	0.26	0.32
Municipal WW	0.13	0.17	0.22	0.27	0.33	0.39	0.43
Total:	**0.85**	**0.99**	**1.41**	**1.37**	**1.50**	**1.80**	**2.15**

Figure 8.1 Waste Management Sector Emissions (MMtCO$_2$e), 1990-2020



Notes: LF – landfill; WW – wastewater; LFGTE – landfill gas to energy; there were no emissions estimated for the Industrial WW sector.

8.4 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 Nevada's LFGTE landfill (Apex), the historical emissions estimates are less certain than current and future emissions estimates (the site was modeled as always being controlled, so the historic emissions are low 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 requirements of the federal New Source Performance Standards/Emission Guidelines (e.g. Lockwood).

Information recently received from Republic Services indicates that the flare has been operational at the Sunrise landfill since 2002; five years earlier than originally reported.[68] Although projected emissions have not been reanalyzed, they are not expected to change significantly.

For the wastewater source category, the key uncertainties are associated with the application of SIT default values for the parameters listed in Table 8.1 (e.g. fraction of the NV population on septic; fraction of BOD which is anaerobically decomposed). The SIT defaults were derived from national data and may not accurately represent conditions in Nevada. Future research will need to provide state-wide estimates of these parameters to improve accuracy**.**

A plasma enhanced melter (PEM) was recently permitted in Storey county to gasify up to 300 tons per day of non-hazardous waste. This facility is not operational and GHG emissions from this facility have not been estimated, so it has not yet been included in the projections for this sector.

[68] Alan Gaddy, Republic Services Area Manager, personal communication, November 13, 2008.

9.0 FORESTRY SECTOR EMISSIONS

9.1 OVERVIEW

Forestland emissions refer to the net carbon dioxide (CO_2) flux[69] from forested lands in Nevada, which account for about 14% of the state's land area.[70] The dominant forest type in the state is pinyon-juniper forest, comprising approximately 90% of forested lands. Forestlands are net sinks of CO_2 in Nevada. Through photosynthesis, CO_2 is taken up by trees and plants and converted to carbon in biomass within the forests. The sector GHG emissions that occur include CO_2, CH_4, and N_2O and are emitted through multiple pathways including the respiration process in live trees, decay of dead biomass, and forest fires. CO_2 flux is the net balance of carbon dioxide removals from and emissions to the atmosphere from the processes described above.

It is estimated that Nevada's forestlands sequester 4.8 $MMtCO_2$ annually, equaling a reduction of approximately 8.5% of total net CO_2e emissions (based on 2005 levels). As forest size in Nevada has remained relatively constant from 1990 to 2008, the sequestration rate is also estimated to remain constant for the entire reporting period.

9.2 METHODOLOGY

Forest Carbon

For over a decade, the United States 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 CO_2 fluxes for the official *U.S. Inventory of Greenhouse Gas Emissions and Sinks*.[71] The national estimates are compiled from state-level data. The Nevada forest CO_2 flux data in this report come from the national analysis and are provided by the USFS.

The forest CO_2 flux methodology relies on input data in the form of plot level forest volume statistics from the Forest Inventory Analysis (FIA). The FIA statistics separate the total forest volume into six distinct carbon pools: live tree, standing dead wood, under-story, down & dead wood, forest floor, and soil organic carbon. FIA data on forest volumes are converted to values for ecosystem carbon stocks (i.e., the amount of carbon stored in each forest carbon pool) using the FORCARB2 modeling system. Coefficients from FORCARB2 are applied to the plot level survey data to give estimates of carbon density (megagrams of carbon per hectare) for a number of separate carbon pools.

CO_2 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 and divided by the number of years between inventory samples. Annual increases in carbon density reflect carbon sequestration in a specific pool; decreases in annual carbon density reveal CO_2 emissions or carbon transfers out of that

69 "Flux" refers to both emissions of CO_2 to the atmosphere and removal (sinks) of CO_2 from the atmosphere

70 Total forested acreage is 9.9 million acres. Acreage by forest type available from the USFS at: http://www.fs.fed.us/ne/global/pubs/books/epa/states/NV.htm. The total land area in NV is 70.3 million acres (http://www.50states.com/Nevada.htm).

71 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/climate change/emissions/usinventoryreport.html.

pool (e.g., through forest fires, or the death of a standing tree transferring carbon from the live tree pool to standing dead wood pool). The amount of carbon in each pool is also influenced by changes in forest area. An increase in area could lead to an increase in the associated forest carbon pools and the estimated flux. Therefore, an increase in a specific pool could be caused by either an increase in overall forest area or a transfer from another carbon pool (i.e. a beetle infestation would increase the pool of standing dead wood, at the expense of the pool of live trees). The sum of carbon stock changes for all forest carbon pools yields a total net CO_2 flux for forest ecosystems.

In preparing these data, 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 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 not used for timber harvesting) or non-woodlands (such as timberlands).

The data shown in Table 9.1 are a summary of the FIA data used to derive the carbon pool and flux estimates for the state of Nevada that are shown in Table 9.2. The previous inventory data came from either a previous FIA cycle or data from the Resources Planning Act Assessment (RPA). Since the Resources Planning Act requires the USFS to report on the state of the country's forest resources on a regular basis the USFS publishes the RPA assessment every five years. The FIA is a key contributor to the RPA. RPA data, which are generally lower in resolution, are sometimes used in place of FIA cycles. The FIA has transitioned from a periodic to annual sampling design, which has created some data sets that are not comparable over time, in which case the RPA data are better suited for estimating carbon densities.[72] As shown in Table 9.1 the current forest carbon pool estimates are derived from 2005 FIA data. The previous inventory data came from a previous FIA cycle or RPA data.

In addition to the forest carbon pools, additional carbon stored as biomass can be 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. In Nevada, the net carbon is estimated to be sequestered annually in wood products is zero; these data are based on a USFS study from 1987 to 1997.[73] Presumably this is due to very little timber harvesting in NV. Additional details on all of the forest carbon inventory methods can be found in Annex 3 to EPA's 2006 GHG inventory for the US.[74]

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72 Jim Smith, USFS. Personal communication, November 7, 2006.

73 http://www.fs.fed.us/ne/newtown_square/publications/technical_reports/pdfs/2003/gtrne310.pdf. See data for Nevada.

74 Annex 3 to EPA's 2006 report can be downloaded at: http://epa.gov/climatechange/emissions/downloads06/07CR.pdf

Table 9.1 Forest Inventory Data Used to Estimate Forest CO_2 Flux

Forest	Current Inventory Data Source	Past Inventory Data Source	Avg. Year[a]	Interval (yr)[b]	Current Forest Area (103 hectares)	Previous Forest Area (103 hectares)
National Forest - Timberland/Reserved/Low Productivity	FISDB21_NV_02_2005	FISDB21_NV_01_1989	2005.1	8.5	290	251
National Forest – Woodlands	FISDB21_NV_02_2005	FISDB21_NV_01_1989	2005.1	8.5	1,126	1,041
Other Public/Private Forest – Timberland/ Reserved/Low Productivity	FISDB21_NV_02_2005	RPAdata_NV____1997	2005.2	19.8	480	212
Other Public/Private Forest – Woodlands	FISDB21_NV_02_2005	FISDB21_NV_01_1989	2005.2	24.7	2,912	2,637
				Totals	4,807	4,140

[a] Average year for the measurements that make up the current FIA inventory data (early 2005 for all forest types).
[b] The number of years between the current inventory source and the past inventory source.

The data in Table 9.1 show an increase of 667 kilo-hectares (1.6 million acres) in forested area during the period of analysis (1993-2003). Over 40% of this increase occurred in woodland forests. However, these increases can potentially be attributed to changes in FIA survey methodology (discussed in further detail under Uncertainties).

Non-CO_2 Emissions from Forest Fires

In order to provide a more comprehensive understanding of GHG sources/sinks from the forestry sector, rough estimates were developed of statewide emissions for methane and nitrous oxide from wildfires and prescribed burns. Emissions from wildfires vary dramatically from year to year, and represent only a small fraction of annual CO_2e emissions. CO_2 emissions from burning are addressed within the methodology described above for carbon stock changes (biomass lost during burning is registered as decreases in the relevant carbon pools).

2002 emissions data developed by the WRAP were used to estimate methane and nitrous oxide emissions from all wildfires and prescribed burns that occurred during that year. Despite the small sample size, these data were then used to create a general baseline for MMtCO_2e/year emissions from wildfires.[75] Methane emissions from this study were added to an estimate of nitrous oxide emissions based on nitrogen oxides (NOx). Emissions of both gases were converted to their CO_2 equivalents and summed to estimate total emissions from fires. The nitrous oxide estimate was made assuming that N_2O was 1% of the emissions of NOx from the WRAP study. The 1% estimate is a common rule of thumb for the N_2O content of NOx from combustion sources.

[75] *2002 Fire Emission Inventory for the WRAP Region Phase II*, prepared by Air Sciences, Inc. for the Western Regional Air Partnership, July 22, 2005.

9.3 RESULTS

Table 9.2 provides a summary of the size of the forest carbon pools for the final survey period and the carbon flux estimates (in units of carbon and CO_2) developed by the USFS.[76] By convention, negative flux values indicate carbon sequestration. A total of 4.8 $MMtCO_2$ are estimated to be sequestered in Nevada forests each year, mostly accumulating in the forest floor. This represents a reduction of approximately 10% from the state's total CO_2e emissions (based on 2005 total gross emissions). Of that reduction, the live tree carbon pool sequesters only about 1.4 $MMtCO_2$/yr, with most of the reduction generated by CO_2 absorption into the forest floor. Zero net flux was estimated in the down & dead carbon pool. Note that this analysis averages out annual fluctuations in carbon sequestration rates over an approximate 8-24 year time interval depending on forest type (see Table 9.1). Uncertainty surrounding soil organic carbon flux survey methodology precludes its inclusion in statewide GHG emission estimates. However, if USFS estimates are assumed to be correct, then the final carbon flux for Nevada forests could be as high as 7.7$MMtCO_2$ sequestered annually.

For the 1990-2005 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 Table 9.2. Hence, there is no change in the estimated future sinks during the projection period.

The baseline figure for CO_2e emissions from wildfires, based on the 2002 WRAP emission data, are about 0.23 $MMtCO_2$e of methane and nitrous oxide from about 88,958 acres burned (82,163 acres by wildfires). This estimate assumes that almost all (94%) of the CO_2e was contributed by CH_4. For the purposes of comparison, another 2002 estimate was made using emission factors from a 2001 global biomass burning study[77] and the total tons of biomass burned from the 2002 WRAP fires emissions inventory. This estimate is nearly 0.27 $MMtCO_2$e, demonstrating good agreement with the WRAP estimate. However, other discrepancies exist, namely that this estimate assumes near equal contributions from methane and nitrous oxide on a CO_2e basis. Further research is needed into the non-CO_2 emissions from forest fires before these estimates should be included into statewide GHG emissions totals.

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[76] Jim Smith, USFS, personal communication, October 2006.

[77] 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.

Table 9.2 Forestry CO_2 Flux Estimates for Nevada (based on 2005 FIA data)

Forest	Current Carbon Stocks by Pool (MMt Carbon)					
	Live Tree	**Standing Dead**	**Under-story**	**Down & Dead**	**Forest Floor**	**Soil Organic Carbon**
National Forest - Timberland/Reserved/Low Productivity	9.4	1.4	1.0	0.6	7.6	9.6
National Forest –Woodlands	36.8	0.2	3.3	1.2	24.9	22.8
Other Public/Private Forest – Timberland/ Reserved/Low Productivity	9.9	2.6	1.8	0.7	10.6	12.8
Other Public/Private Forest – Woodlands	67.5	0.1	8.3	2.1	62.9	58.6
Totals	124	4.2	14.4	4.6	106	104

Forest	Average Carbon Flux by Pool (MMt C/yr)					
	Live Tree	**Standing Dead**	**Under-story**	**Down & Dead**	**Forest Floor**	**Soil Organic Carbon**
National Forest - Timberland/Reserved/Low Productivity	0.34	0.02	-0.03	0.03	-0.04	-0.05
National Forest –Woodlands	-0.80	-0.02	-0.02	-0.02	-0.18	-0.18
Other Public/Private Forest – Timberland/ Reserved/Low Productivity	-0.02	-0.10	-0.06	-0.01	-0.26	-0.31
Other Public/Private Forest – Woodlands	0.17	0.00	-0.04	0.00	-0.27	-0.26
Totals	-0.31	-0.10	-0.15	0.00	-0.75	-0.79

Forest	Average Carbon Flux by Pool (MMt CO_2/yr)					
	Live Tree	**Standing Dead**	**Under-story**	**Down & Dead**	**Forest Floor**	**Soil Organic Carbon**
National Forest - Timberland/Reserved/Low Productivity	1.24	0.07	-0.11	0.10	-0.14	-0.17
National Forest –Woodlands	-2.94	-0.07	-0.08	-0.07	-0.66	-0.65
Other Public/Private Forest – Timberland/ Reserved/Low Productivity	-0.08	-0.38	-0.21	-0.04	-0.96	-1.13
Other Public/Private Forest – Woodlands	0.64	-0.01	-0.14	0.01	-1.01	-0.95
Totals	-1.14	-0.38	-0.55	0.00	-2.76	-2.91

Total Forest Flux ($MMtCO_2e$)=	-4.8
Harvested Wood Products[a]	0.0
Including Soil Organic Carbon	-7.7

[a] Source: http://www.fs.fed.us/ne/newtown_square/publications/technical_reports/pdfs/2003/gtrne310.pdf; for Nevada, harvested wood products were estimated to sequester 0.0 MMtC during the period 1987-1997).

9.4 UNCERTAINTIES

It is important to note that there were methodological differences in the two FIA cycles that can produce different estimates of forested area and carbon density. For example, in the Rocky Mountain Region of the US, 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, and potentially accounting for all of the increases in forest area detailed in Table 9.1). In woodland areas, 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). Also, surveys since 1999 include all dead trees on the plots, but data prior to that are variable in terms of these data. 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 comprehensively estimated by the USFS. In states like Nevada that are in the Rocky Mountain Region and have substantial areas of woodlands, the change in definition could contribute significantly to the increases seen in forested area, which would translate into increases in CO_2 pools and large net negative CO_2 fluxes. For these reasons, the USFS provided flux estimates separately for woodlands, so that the relative influence of the woodlands class on total net CO_2 fluxes in Nevada could be discerned. As shown in Table 9.2, the contribution from the woodland areas drives a significant fraction of the flux estimate statewide (over 75%). Given the modifications to the FIA survey methods, the forest flux estimates for Nevada (-4.8 $MMtCO_2$) may be viewed as high.

One approach to adjusting the USFS estimates to account for the possible overestimate of carbon fluxes on woodlands in Nevada is to assume that all increases in forest area are due to changes in FIA definitions, thus there was no actual net increase in forest area or forest growth in the woodlands category. In this case, the carbon stocks would remain constant over time and the carbon flux can be assumed to be zero. This approach gives a total forest CO_2 flux for Nevada of about -1.8 $MMtCO_2$ per year (a 77% lower rate of sequestration). This may overcompensate for the USFS definition change in the woodlands class, but no estimate can be sure until more is understood about how changes in FIA survey methodology affect woodland area estimates for Nevada

The baseline estimate for emissions from forest fires and prescribed burns is based on only one year of data. This remains the best estimate to date, despite the fact that emissions from wildfires vary dramatically from year to year. For example, the sampling year for wildfire emissions (2002) burned less than one tenth of the almost 950,000 acres burned in Nevada during the 1996 fire season.[78] Given the large swings in fire activity from year to year, these estimates are not included in 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 fires contribute on the order of 0.2 – 2.0 $MMtCO_2e$ annually in Nevada from methane and nitrous oxide emissions. This represents a potential 0.5% - 5% increase in total statewide net CO_2e emissions (based on 2005 levels). Increased sampling and refining

[78] *1996 Fire Emission Inventory*, Draft Final Report, prepared by Air Sciences, Inc. for the Western Regional Air Partnership, December 2002.

model parameters for wildfire emissions will be necessary to increase accuracy of future GHG emissions reports.

While estimating the carbon flux of forest lands in Nevada revealed an 8% reduction in total statewide emissions, expanding this section to include the carbon sinks present in non-forest land could vastly increase this estimate. Very little research exists on carbon sequestration in sagebrush, or, conversely, on non-CO_2 emissions from brush fires. Since 81% of the land area of the state is classified as rangeland,[79] this could represent a very significant area for future refinement of statewide GHG emissions inventories. Research is currently being conducted in this area and may allow better estimates to be made in the future.

[79] Nevada Natural Resources Status Report, Nevada Department of Conservation and Natural Resources, June 2001.