INVENTORY OF CALIFORNIA GREENHOUSE GAS EMISSIONS AND SINKS: 1990 TO 2002 UPDATE

PREPARED IN SUPPORT OF THE 2005 INTEGRATED ENERGY POLICY REPORT

STAFF PAPER

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EXECUTIVE SUMMARY

From 1990 to 2001 California's economy experienced the largest gross state product (GSP) growth of any state in the country.[1] During the same period, the state successfully slowed the rate of growth in greenhouse gas (GHG) emissions, demonstrating that California can have both a strong economy and high environmental standards.

In spite of the slowed growth rate, California's emissions of greenhouse gases are large and growing. As the second largest emitter of GHGs in the United States (U.S.) and tenth largest in the world,[2] California's sheer magnitude significantly affects global warming.

This paper updates California's statewide inventory of GHG emissions to support this positive development. It also extends the inventory period from 1999 to 2002, and uses 2002 data, the most recent available from the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA). For the first time ever, this inventory reports GHG emissions from out-of-state electricity along with in-state GHG emissions and projects future emissions trends.

California's successful slowing of the rate of growth of GHG emissions is largely due to the success of its energy efficiency and renewable energy programs and a commitment to clean air and clean energy. In fact, the state's programs and commitment lowered its rate of growth in GHG emissions by more than half of what they likely would have been otherwise.[3] What's more, California's energy programs and policies have had the dual benefit of not only reducing its GHG emissions, but also reducing its energy demand.

Although California's total emissions are larger than every state but Texas, California has relatively low carbon emission intensity. In 2001, California ranked fourth lowest in carbon emissions per capita and fifth lowest among the states in carbon dioxide (CO_2) emissions from fossil fuel consumption per unit of GSP.

In 2002, California produced 493 million metric tons of CO_2-equivalent[4] greenhouse gas emissions. The transportation sector is the single largest category of GHG emissions, producing 41 percent of the state's total emissions. Most of California's emissions, 81 percent, are CO_2 emissions produced from the combustion of fossil fuels.

For the first time, the California GHG emissions inventory excludes all international fuel uses, reporting them on separate lines. Including these international emissions would increase total emissions by 27 to 40 million metric tons of CO_2–equivalent GHG emissions.

Electricity generation is the second largest category of GHG emissions. In particular, out-of-state electricity generation has shown higher carbon intensity than in-state generation. While imported electricity is a relatively small share of California's electricity mix (ranging from one-fifth to one-third of total electricity supply), out-of-state electricity generation sources are contributing 50 percent of the GHG emissions associated with electricity consumption in California.

Because global warming gases affect the entire planet, not just the location where they are emitted, policies developed to combat global warming should include the entire fuel cycle whenever possible. Staff findings and policy options to further support accurate reporting of GHG emissions include the following:

- Use more current activity data.

- Perform a more detailed review of industrial uses of fossil fuels to classify when they are used as fuel versus when they are used as a process input and not released into the atmosphere at that step in their usage chain.

- Industrial wastewater emissions occur from processing fruits and vegetables; red meat and poultry; and pulp and paper. Methane and nitrous oxide emissions from these activities are not yet included in the California inventory, and should be added.

- Landfill methane emissions should be reviewed in more detail. Values look low compared to 1990-1999 inventory. Some have reported higher values. These discrepancies need to be resolved.

- Develop California-specific data for sulfur hexafluoride (SF_6) emissions from electric utilities.

- Develop California-specific emissions factors for emissions of methane and nitrous oxide from manure management.

- Develop California-specific emissions factors for enteric fermentation from animal husbandry.

INTRODUCTION

This paper updates California's statewide inventory of GHG emissions, using 2002 data, the most recent data available from the DOE's EIA. It also extends the period of the California GHG inventory from 1999 to 2002.

The California GHG emissions inventory is an estimate of anthropogenic[5] emissions of CO_2, methane, nitrous oxide, and various high global warming potential gases that contribute to warming of the earth's atmosphere and oceans. All these gases have been identified as forcing the earth's atmosphere and oceans to warm above naturally occurring temperatures.[6]

The preceding State of California inventory of anthropogenic GHG emissions was reported in *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999*.[7] It covered the period from 1990 to1999, and was prepared under contract to the California Energy Commission (Energy Commission) by ICF Consulting of Washington, D. C. The 1990 -1999 inventory was based on guidance documents also prepared by ICF Consulting for the U.S. Environmental Protection Agency (EPA).[8]

Because they provide a comprehensive and consistent data source without significant gaps or overlap, EIA data were used in the 1990-1999 inventory and for most of this inventory update. These EIA data were supplemented with Energy Commission data in a report titled *California Energy Balances Report (*Energy Balance*)*[9] prepared by Lawrence Berkeley National Laboratories for the Energy Commission's Public Interest Energy Research Program.

The new inventory relies heavily upon data sources and procedures used by ICF Consulting in preparing the 1990-1999 inventory, and the national GHG emissions inventory.[10] In some instances, staff used newer data available from the Energy Commission and the California Air Resources Board (CARB), which allow for a more refined treatment. These changes are explained in the body of this document.

This paper presents the methodology and approach used in the current inventory update. Where a data or an analysis change is made, staff has provided information in this paper to fully document the change. The 1990-1999 inventory provides full technical documentation. All changes are applied over the entire time span of the inventory to more properly show GHG inventory trends.

The paper next provides a summary of California's GHG emissions, followed by a discussion of projected GHG emissions trends[11] for carbon dioxide emitted from fossil fuel combustion. Fossil fuels produce over 80 percent of California's GHG inventory and are responsible for large but varying percentages of GHG emissions for other states. After the carbon dioxide trend analysis, the paper summarizes the methods used to estimate California's inventory of GHG emissions. Next, this paper discusses ways to improve future versions of the California GHG emissions inventory. Finally, Appendix A provides documentation for improvements made to the California GHG inventory.

Previous California GHG Inventories

In October of 1990, the California Energy Commission published[12] the first inventory of greenhouse gas emissions for the State of California. This inventory was only for one year (1988) and only for carbon dioxide, with results expressed in short tons of carbon. The estimated emissions were 144.5 million tons of carbon (which converts to 480.7 million metric tons of carbon dioxide). In-state emissions were estimated at 125.1 tons of carbon (416.1 million metric tons of carbon dioxide) and out-of-state emissions were an additional 19.4 tons of carbon (64.5 million metric tons of CO_2).

In March of 1997, the Energy Commission published[13] its second inventory of GHG emissions for the State of California. This second inventory was also only for one year (1990) but included an estimate for methane and nitrous oxide, in addition to carbon dioxide. It used 100-year global warming potentials of 11 for methane and 270 for nitrous oxide. Results were expressed in short tons of CO_2-equivalent, using the global warming potentials to obtain the CO_2-equivalents for methane and nitrous oxide. Estimated in-state emissions for this second inventory were 452.3 million short tons of CO_2-equivalent (410.3 million metric tons of CO_2-equivalent). Estimated out-of-state emissions were 16.0 million short tons of carbon (53.1 million metric tons of CO_2 -equivalent). Total estimated 1990 emissions were 463.4 million metric tons of CO_2-equivalent. These estimates include international bunker fuels.

In January 1998, the Energy Commission published[14] its next GHG inventory. This inventory covered 1990 through 1994, and also included methane and nitrous oxide in addition to carbon dioxide. It used 100-year global warming potentials of 21 for methane and 310 for nitrous oxide, as did subsequent GHG inventories. Results were also expressed in short tons of CO_2-equivalent. Estimated in-state 1990 emissions were 456.3 million short tons of CO_2-equivalents (414 million metric tons of CO_2-equivalent). Estimated out-of-state emissions were about 54.2 million metric tons of CO_2-equivalent. Total estimated 1990 emissions were 470 million metric tons of CO_2-equivalent. Estimated in-state 1994 emissions were 458.2 short tons of CO_2-equivalent (415.7 million metric tons of CO_2-equivalent). The report did not list out-of-state emissions for 1994.

Legislative Requirements for Inventory Updates

In September 2000, the California Legislature passed legislation (Senate Bill (SB) 1771 [Sher], Chapter 1018, Statutes of 2000), requiring the Energy Commission to update the state's inventory of GHG emissions in consultation with other agencies.

The statute required the Energy Commission to update the inventory in January 2002, and every five years after that.

The Energy Commission prepared its first statewide inventory in response to SB 1771, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999*,[15] based on the best information available at the time of publication. The inventory was developed using guidelines adopted by the Intergovernmental Panel on Climate Change and was consistent with the methods being used by the EPA.

SB 1771 requires the Energy Commission to update the GHG inventory in January 2007. This update is produced to incorporate newer information and to allow policy makers to use the most current information and data available.

This inventory update compares California's emissions of GHG emissions with emissions of other states. Limited information was available to allow a complete and thorough analysis and discussion of the impact of air quality and energy policies and programs on GHGs. During 2004 and 2005, the Energy Commission staff updated the statewide inventory using 2002 data, which was the most recent data available.

Summary of California's GHG Emissions

In 2002 California produced 493 million metric tons of CO_2-equivalent GHG emissions. As shown in Figure 1, 82 percent were emissions of carbon dioxide from fossil fuel combustion, 2.2 percent were from other sources of carbon dioxide, 6.2 percent were from methane, and 6.6 percent were from nitrous oxide. The remaining source of GHG emissions was high global warming potential gases, 3.4 percent.

The percentage of climate change associated with each gas is similar for each year over the 1990 to 2002 period. However, high global warming potential gas percentages are rising somewhat.

Composition of California's GHG Emissions

Carbon dioxide emissions from anthropogenic activities represent 84 percent of total greenhouse gas emissions. Carbon dioxide emissions are mainly associated with carbon-bearing fossil fuel combustion with a portion of these emissions attributed to out-of-state fossil fuel used for electricity consumption within California. Other activities include mineral production, waste combustion and land use, and forestry changes. Some anthropogenic activities lead to a reduction in atmospheric concentration of carbon dioxide. These are called carbon dioxide or (CO_2) "sinks."

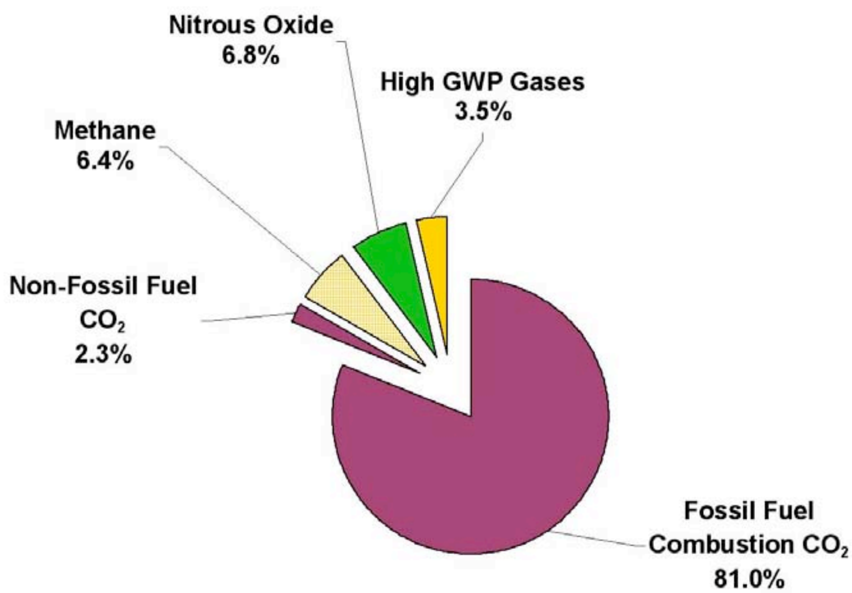
Anthropogenic activities generate methane emissions and represent approximately 6 percent of total GHG emissions. These emissions are reported in CO_2-equivalent units to reflect the global warming potential of methane compared to carbon dioxide. Agricultural activities and landfills comprise the major sources of these emissions.

Anthropogenic activities also generate nitrous oxide emissions; nitrous oxide is sometimes called “laughing gas.” Agricultural activities and mobile source fuel combustion comprise the major sources of these emissions. Nitrous oxide emissions comprise approximately 7 percent of overall GHG emissions.

A class of gases called “high global warming potential gases” makes up the final set of anthropogenic gases that contribute to global warming.[16] These include gases used in industrial applications to replace gases associated with ozone depletion over the Earth and sulfur hexafluoride (SF_6) used as insulating materials in electricity transmission and distribution.

High global warming potential gases comprise a low percentage of overall GHG emissions over this time period, although the estimated emissions are difficult to quantify and are less certain than other emissions categories. Although small in magnitude, these gases are increasing at a faster rate than other GHGs.

Figure 1—California GHG Composition by Type of Gas in 2002

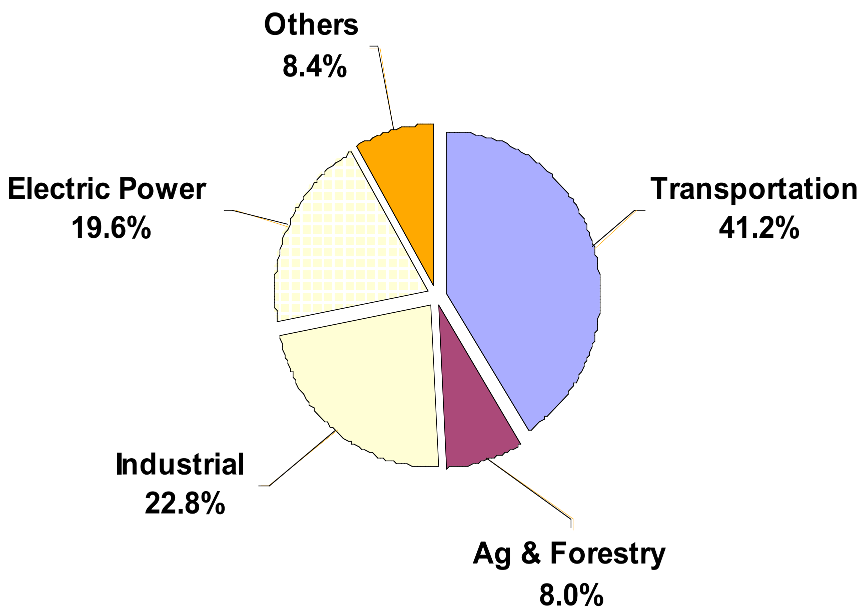


Source: California Energy Commission

End-Use Sectors Contributing to California’s GHG Emissions

As shown in Figure 2, fossil fuel consumption in the transportation[17] sector was the single largest source of California’s GHG emissions in 2002, with the industrial[18] sector as the second largest source, and electricity production,[19] from both in-state and out-of-state sources as the third largest source. Agriculture,[20] forestry,[21] commercial,[22] and residential[23] activities comprised the balance of California's greenhouse gas emissions.

Figure 2—Sources of California's 2002 GHG Emissions (By End-Use Sector)



Source: California Energy Commission

GHG Emissions Trends

This section discusses trends in California's gross emissions of GHG emissions. Thus, the values discussed in this section do not account for CO_2 sinks from forest, rangelands, or landfill and yard trimming disposal.

This section also excludes international aviation and marine vessel uses of jet fuel, residual oil,[24] and distillate oil because they are international fuel uses and the standard GHG emissions inventory protocol excludes them. Domestic jet fuel, residual oil, and distillate oil uses are included in the analysis.

The trends discussed in this section include carbon emissions from imported electricity, including out-of-state coal-fired power plants owned by California electric utility companies that provide electricity to California.

California's GHG emissions are large and growing as a result of population and economic growth and other factors. From 1990 to 2002 total GHG emissions rose nearly 12 percent; however, they are expected to increase at least 24 percent from 1990 to 2020, if current trends continue.

Trends in California Greenhouse Gas Composition

In 1990, fossil fuel-related carbon dioxide emissions comprised 81 percent of California's total GHG emissions, including CO_2 emissions from electric power imported to the state.[25] This percent held steady at 81 percent in 2002. Non-fossil fuel carbon dioxide contributed 2.2 percent in 1990, and 2.3 percent in 2002.

Methane emissions comprised 6.4 percent of California's total GHG emissions in 1990. The percentage held constant at 6.4 percent in 2002. Nitrous oxide emissions trends were similar to methane, representing 6.7 percent of total emissions in 1990, and increasing to 6.8 percent in 2002. High global warming potential gas emissions comprised 2.0 percent of California's total greenhouse gas emissions in 1990, increasing to 3.5 percent in 2002.

Trends in California's GHG Emissions End-Use Categories

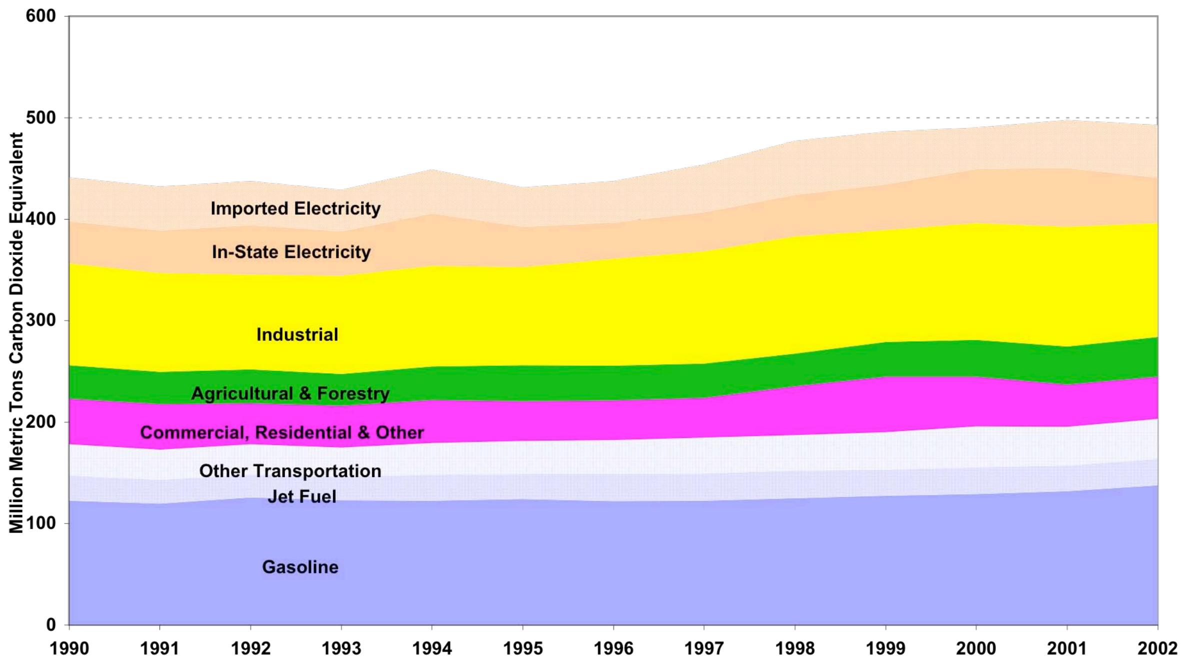
Figure 3 shows year-by-year trends for transportation (gasoline consumption, jet fuel consumption, and other transportation fuel use); commercial, residential and other fuel use; agricultural and forestry fuel use; industrial fuel use; and electricity production (both in-state and imported electricity). Overall, California's GHG emissions increased 11.5 percent over the 1990 to 2002 period.

Transportation

The bottom band in Figure 3 shows the 1990 to 2002 trends for carbon dioxide, methane, and nitrous oxide emissions from gasoline consumption in California. The second band from the bottom shows trends for the same three gases from jet fuel consumption, and the third band shows trends for the same three gases due to other[26] transportation fuel uses. The three bands together show trends for total transportation fuel consumption.

These data show a modest increase over the 1990 to 2002 period, 13.3 percent overall. Gasoline emissions increased 12.2 percent; jet fuel emissions increased 6.2 percent. Jet fuel actually increased 11.0 percent from 1990 to 2000, but then declined in 2001-2002, likely due to the events of September 11, 2001. All other transportation emissions increased by 27.2 percent.

Figure 3—California's Gross GHG Emissions Trends



Source: California Energy Commission

Commercial, Residential, Agricultural, Forestry, and Industrial Sectors

Greenhouse gas emissions from fuel use in the commercial, residential, and other[27] end use sectors are shown in Figure 3. These emissions are comprised mostly of carbon dioxide, but include small amounts of methane and nitrous oxide gases. These emissions both increase and decrease over the 1990 to 2002 period, with an overall decrease of 7.0 percent in 2002.

Greenhouse gas emissions from the agricultural and forestry sectors are comprised mostly of nitrous oxide from agricultural soil management, carbon dioxide from forestry practice changes, methane from enteric fermentation, methane, and nitrous oxide from manure management. These emissions both increase and decrease over the 1990 to 2002 period, with an overall increase of 17.8 percent.

Greenhouse gas emissions from the industrial sector are produced from many industrial activities. For example, carbon dioxide is produced from fossil fuels, with the major contributions from oil and natural gas extraction, crude oil refining, food processing, stone, clay, glass and cement manufacturing, chemical manufacturing, and cement production.

Other industrial activities produce methane emissions, with the major contributions from petroleum and natural gas supply systems and wastewater treatment. Still other industrial activities produce nitrous oxide emissions with the major contributions from nitric acid production and municipal wastewater treatment. Another industrial sector set of emissions are called high global warming potential gases, and are comprised mostly of ozone-depleting[28] gases.

Industrial sector greenhouse gas emissions both increased and decreased over the 1990 to 2002 period, with an overall increase of 12.3 percent in 2002.

GHG Emissions from Electricity Generation

The top two bands of Figure 3 above show greenhouse gas emissions from electricity produced for use in California. The solid band includes emissions from electricity production within California and the stippled band shows emissions from electricity produced outside California that serves demand within California. Although values vary from year-to-year, California's longer-term electricity consumption has grown only slowly, increasing from 190,400 gigawatt-hours in 1990, to 209,600 gigawatt-hours in 2002, an overall increase of 10 percent in 12 years.

In-state emissions are comprised of carbon dioxide emissions from natural gas combustion in utility power plants, combined heat-and-power facilities and merchant power plants, and from coal[29] combusted in combined heat-and-power facilities. In-state emissions also include SF_6 emissions associated with operation of power switching equipment and transformers. In-state emissions peaked in 2001, then decreased in 2002 due to a 23 percent reduction in natural gas use in electricity production compared to 2001.

In-state electricity generation emissions increased 7.8 percent over the 1990 to 2002 period.

Out-of-state emissions are comprised of carbon dioxide emissions, mostly from coal-fired power plants. Although out-of-state electricity comprises only about 22 to 32 percent of California's total electrical energy consumption, it comprises approximately 50 percent of the total GHG emissions associated with serving electricity demand in California. Some out-of-state emissions are from coal-fired electric power plants owned by California electric utility companies. Out-of-state emissions increased in 2002 to offset reduced in-state electricity production.

Out-of-state electricity generation has shown higher carbon intensity than in-state generation in the past. Since 1990, in-state electricity produced 185 to 280 metric tons of CO_2 per gigawatt-hour, while imported electricity from fossil fuels produced 660 to 1,350 metric tons of CO_2 per gigawatt-hour. This carbon intensity variation is affected by the year-to-year availability of hydropower and other factors.
Out-of-state electricity generation emissions increased 19.4 percent over the 1990 to 2002 period.

Future Greenhouse Gas Emissions Trends

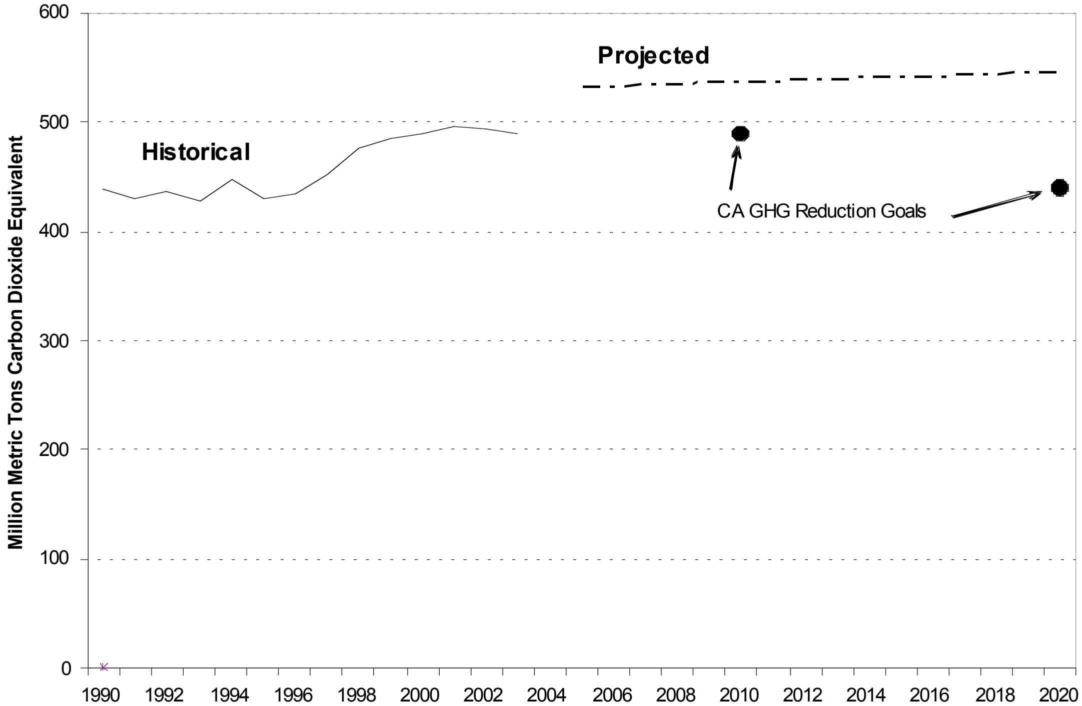
Greenhouse gas emissions are expected to grow in the future as California continues its population and economic expansion. Figure 4 shows projected future GHG emissions under a "business-as-usual" trend.

Staff projected GHG emissions using forecasts of gasoline demand from the *2005 Integrated Energy Policy Report (IEPR)*, which includes the CARB's regulations of GHG emissions from vehicles, and the *2003 IEPR* forecasts for emissions from natural gas, jet fuel, and diesel use. Staff assumed that other greenhouse gas emissions categories remained constant at 2002 values because Energy Commission forecasts were not available for them.

These projected GHG emissions should be considered rough estimates and assume no new emissions reduction strategies beyond those currently in place. In addition to the CARB GHG regulations mentioned above, these emissions reduction strategies include the switch from methyl tertiary butyl ether (MTBE) to ethanol in gasoline, which occurred after 2001, Energy Commission building standards that take effect in 2005, and additional fuel demand reductions that occurred after 2001 due to savings mandated by the California Public Utilities Commission.

Figure 4 also shows near-term and mid-term greenhouse gas emissions reduction targets established by Governor Schwarzenegger in Executive Order S-3-05,[30] signed on June 1, 2005. The order calls for a near-term target of reducing emissions to year 2000 levels by 2010, and a mid-term target of returning to1990 levels by 2020.

Figure 4—Historical and Projected California GHG Emissions



Source: California Energy Commission

Greenhouse Gas Emissions Intensity Trends

This section places California's GHG emissions into context with its population and its level of economic activity as measured by its GSP. Because all 50 states are included in this section, only in-state emissions are addressed in this section. Due to limited availability of data, this section addresses only carbon dioxide from fossil fuel combustion for the 1990 to 2000 period.

Carbon dioxide emissions from fossil fuel combustion comprise 60 to 90 percent of the total GHG emissions of individual states,[31] and the trends that follow should be viewed within this context. Although some states indicate that CO_2 emissions from fossil fuel combustion is much less than 90 percent of total GHG emissions, total emissions from these states are modest in magnitude. On a national average, carbon dioxide emissions from fossil fuel combustion comprise about 83 percent of total greenhouse gas emissions.

To mitigate some of the effects of its large and growing population and expanding economy, California began in the 1970s to aggressively implement energy efficiency measures for fuel-burning equipment and electricity demand. Both of these policies have significantly reduced fuel consumption and associated GHG emissions.

Compared to other states, California has relatively low carbon use intensity due to the success of state energy efficiency programs.

Another factor that has reduced California's fuel use and greenhouse gas emissions is a mild climate compared to that of many other states. The mild climate reduces the demand for heating fuel during winter but somewhat increases electricity for summer air conditioning. This mild climate, combined with a complex topography and meteorology, also produced some of the nation's worst air pollution over the past quarter century, which has led to aggressive pollution reduction efforts. As a direct result, California uses relatively low carbon intensity fuels in its power plants and other industrial sectors.

Over the 1990 to 2000 period, California's population grew by 4.1 million people, the largest increase in the United States; however, California ranks only 18th from the largest when its population growth is measured in percent increase.

Correspondingly, California's economic base, measured by GSP, grew from $788 billion in 1990 to $1.1 trillion in 2000, the largest GSP growth in the United States;[32] however, California ranks only 30th when its GSP growth is measured in percent increase.

Figure 5 shows in-state CO_2 emissions from fossil fuel combustion in each of the 50 states over the 1990 to 2000 period, as calculated by the EPA. Year 2000 is the most current year available from EPA. Although it is difficult to identify individual states, several factors are apparent from the figure: (1) most states show a fairly stable trend over the 1990 to 2000 period; (2) Texas has the highest emissions of in-state carbon dioxide emissions from fossil fuel combustion and shows a rising trend; and (3) California has the second highest emissions, which are fairly stable over the time horizon.

California has about half as much carbon dioxide emissions as Texas. However, Texas' emission growth rate ranks 27th out of the 50 states, and California's growth rate ranks 44th when measured in percentage increase. Emissions from other states are all so similar to one another that they need not be individually identified; for the most part they are all considerably lower than Texas or California.

Figure 6 shows in-state fossil fuel carbon dioxide emissions per person for each of the 50 states. This figure was developed by dividing the population of each state into the fossil fuel emissions from Figure 5. Again, individual states are difficult to identify although several trends are apparent from the figure. First, Wyoming and North Dakota have the highest emissions per capita, not Texas or California. Second, emissions per capita show a fairly flat trend for most states. This means that population growth and carbon dioxide emissions from fossil fuel combustion are well correlated for most states. In terms of per capita emissions, each state shows remarkably stable emissions over the 1990 to 2000 period.[33]

Figure 7 shows fossil fuel carbon dioxide emissions per unit of GSP[34] for each of the 50 states. In this figure, once again individual states are difficult to identify, but trends are apparent. Wyoming has the largest emissions in terms of CO_2 emissions from fossil fuel combustion per unit of GSP and North Dakota ranks second. Texas ranks near the bottom one-third and California ranks near the bottom.

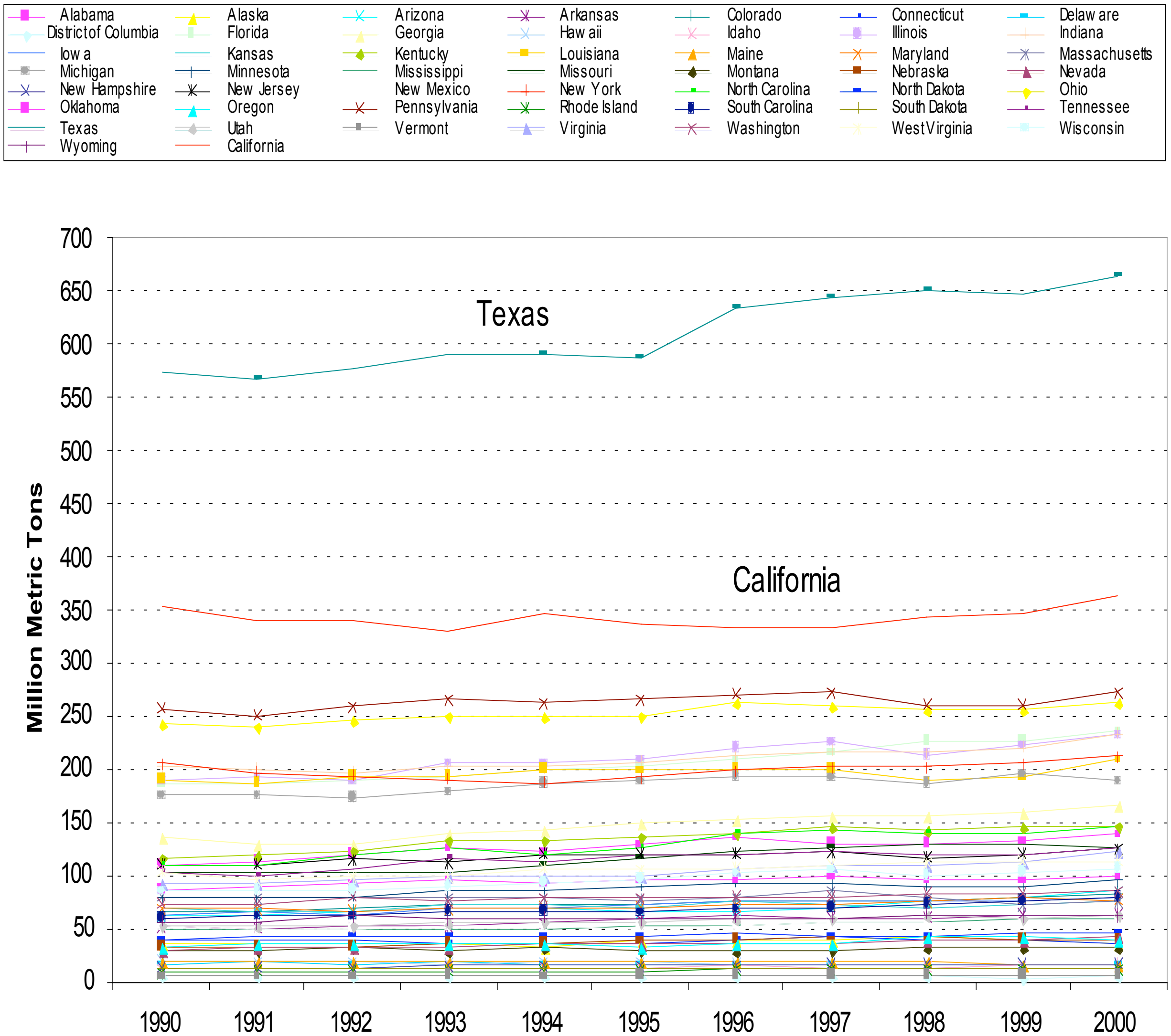
This figure shows a trend of reduced greenhouse gas emissions per million dollars of GSP for most states. In general, GSP increases while carbon dioxide emissions from fossil fuel combustion remain steady over the same time period, as shown in Figure 5. In Figure 7, each state shows a reduction over time because the increase in GSP is greater than the increase in CO_2 emissions from fossil fuel combustion.

Figures 5, 6, and 7 all show a similar result in terms of relative ranking by state, regardless of year. Data for 2000 were used to construct Figure 8, which shows the ranking of the states for carbon dioxide from fossil fuel combustion per capita and Figure 9, which shows the ranking of the states for carbon dioxide from fossil fuel combustion per million dollars of GSP. Because Figures 5, 6, and 7 all show similar trends, Figures 8 and 9 would look similar regardless of the year chosen to display relative rankings.

Figure 8 shows the relative ranking of states for emissions of carbon dioxide from fossil fuels per capita for the year 2000. California has the fourth lowest emissions per capita, following Washington (District of Columbia), Connecticut, and Rhode Island.

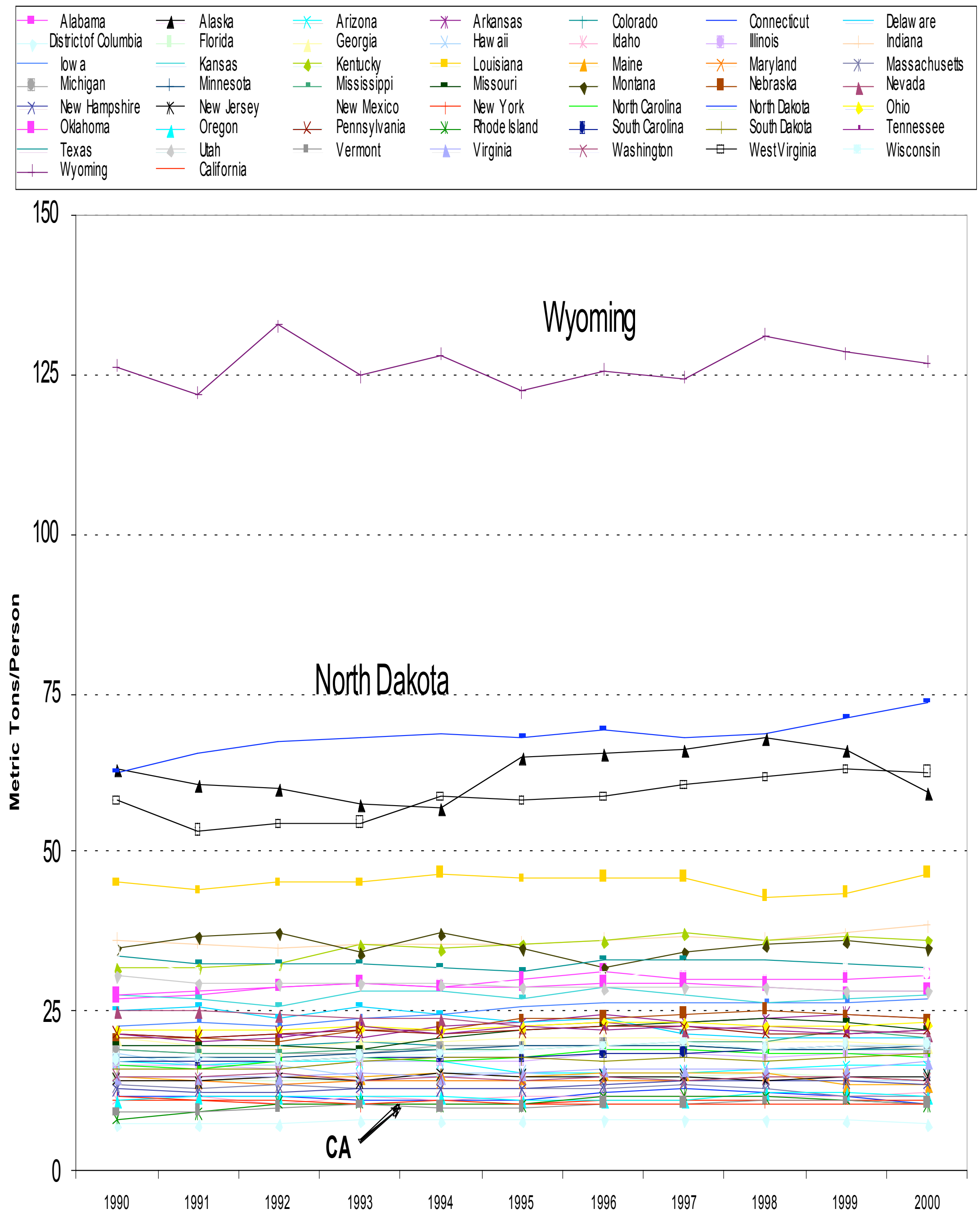
Figure 9 shows relative ranking of states in terms of emissions of carbon dioxide from fossil fuels per unit of GSP for the year 2000. California has the fifth lowest emissions per million dollars of GSP, following Washington (District of Columbia), Connecticut, Massachusetts, and New York.

Figure 5—Carbon Dioxide Emissions from Fossil Fuel Combustion



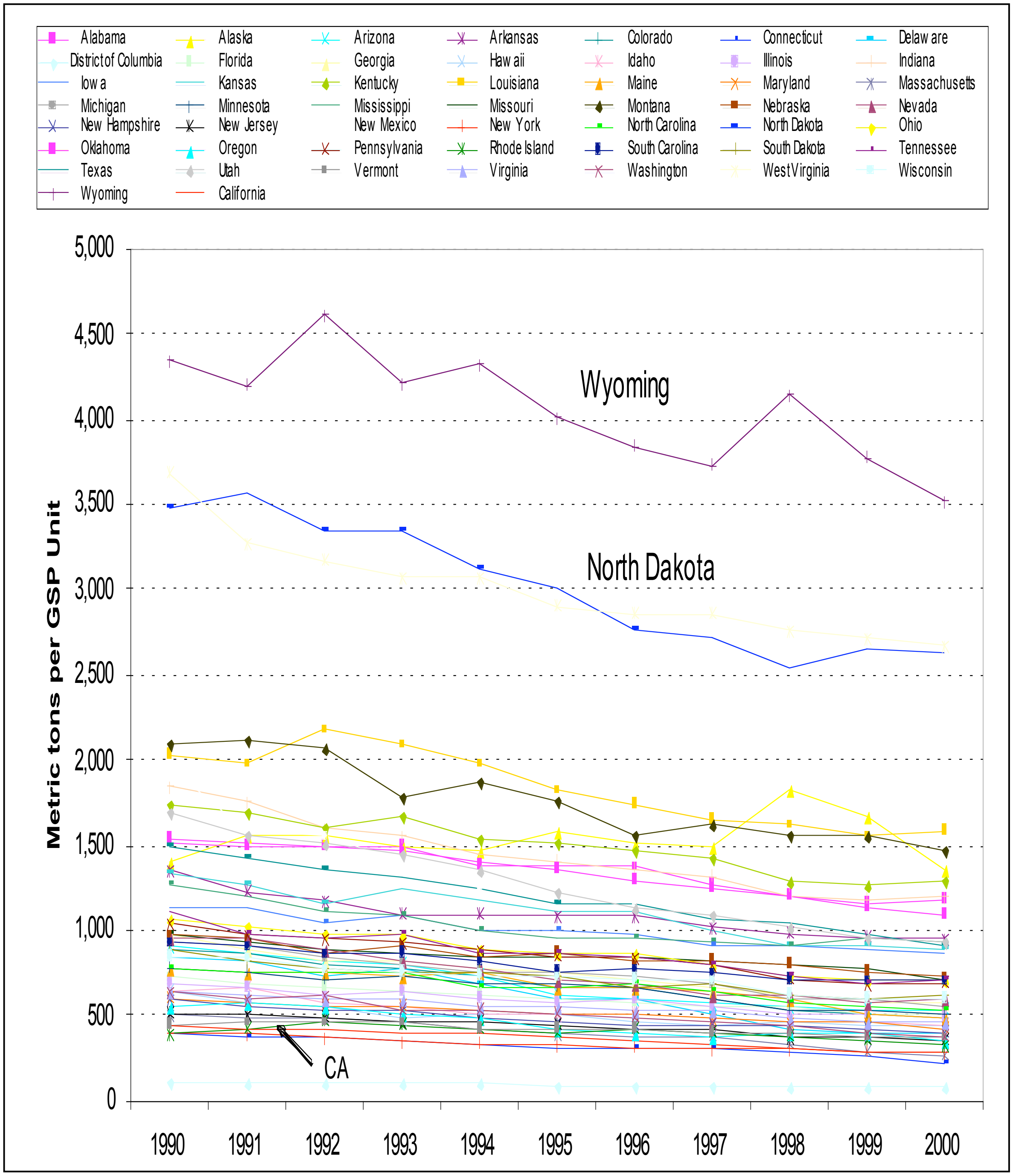
Source: California Energy Commission

Figure 6—Carbon Dioxide Emissions from Fossil Fuel Combustion per Capita



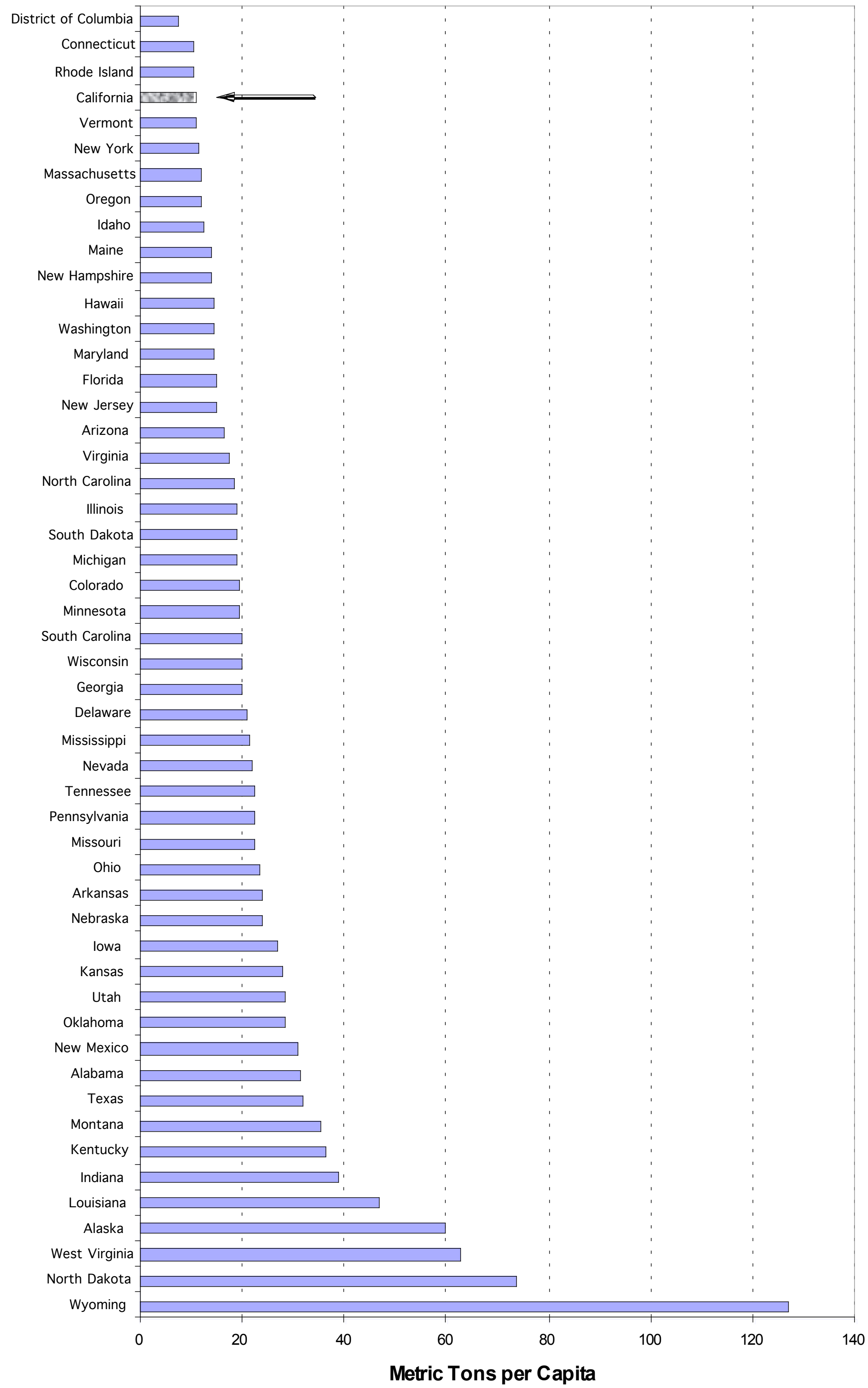
Source: Energy Commission

Figure 7-Carbon Dioxide Emissions from Fossil Fuel Combustion per GSP Unit



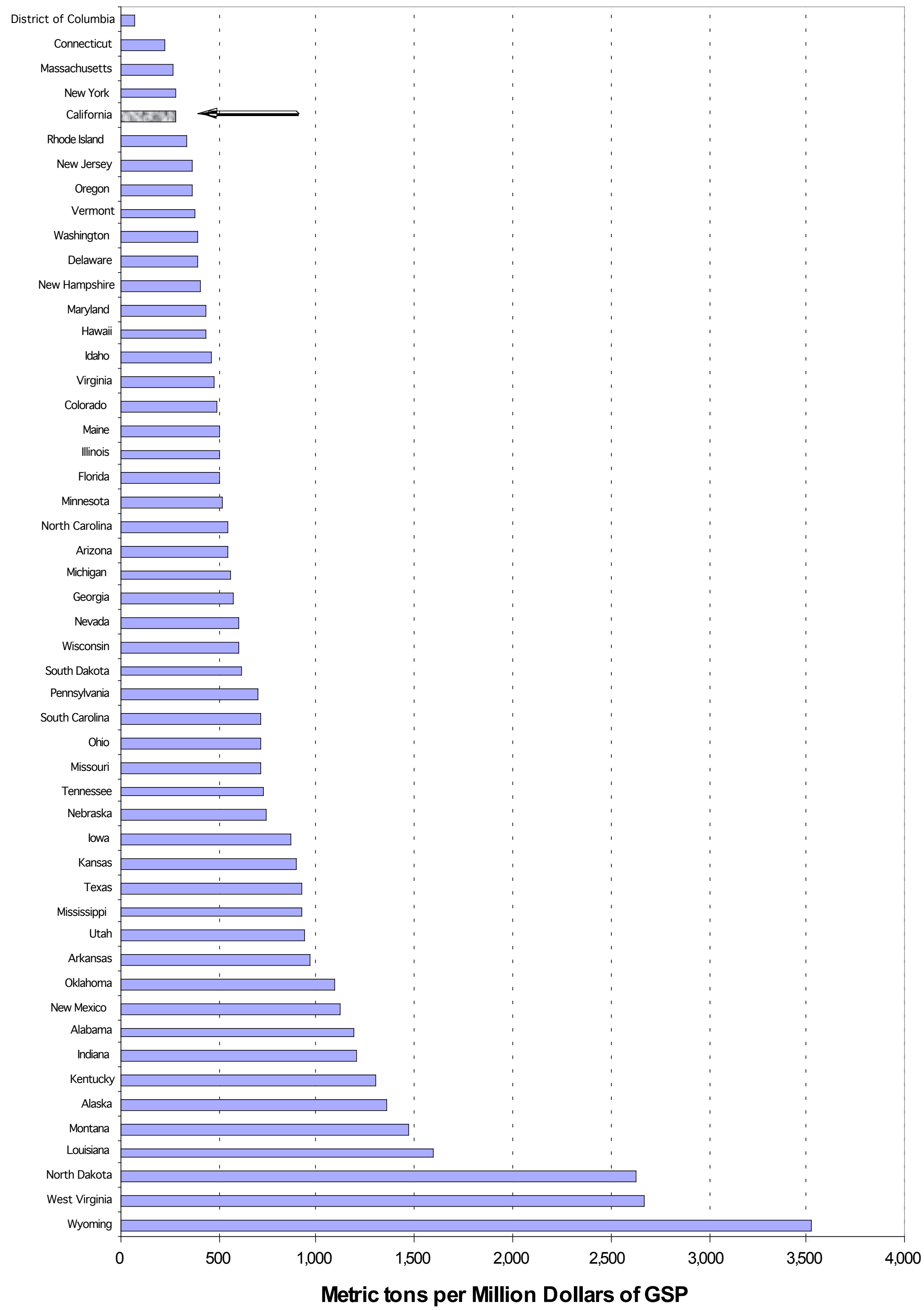
Source: California Energy Commission

Figure 8-Carbon Dioxide Emissions from Fossil Fuels per Capita (2000)



Source: California Energy Commission

Figure 9-Carbon Dioxide Emissions from Fossil Fuels per Unit of GSP (2000)



Source: California Energy Commission

GHG Inventory Update

Table 1 summarizes the updated GHG emissions inventory, covering the 1990 to 2002 period. This table displays GHG emissions for carbon dioxide, methane, nitrous oxide, and high global warming potential gases. More detail for each of these gases can be found in Appendix A. The line numbers in the following descriptions provide the reader a reference to the data in Table 1.

Total gross carbon dioxide emissions from anthropogenic activities are shown in Line 1. These values are obtained by adding Line 2 and Lines 9 through 15. Line 2 is a summary of Lines 3 to 8. These show gross carbon dioxide emissions for fossil fuel combustion in residential, commercial, industrial, transportation, electricity generation, and other end-use sectors. Lines 9 through 15 show carbon dioxide emissions from non-fossil fuel sources, and line 16 shows changes in anthropogenic activities that consume carbon dioxide (also called sinks). Net carbon dioxide emissions are gross emissions from Line 1 minus the sinks in Line 16. These net emissions are shown in line 17.

The next portion of Table 1 (Lines 18 through 28) includes anthropogenic activities that generate methane emissions. These are reported in CO_2-equivalent units to reflect the global warming potential of methane compared to carbon dioxide. Agricultural activities and landfills comprise the major sources of these emissions. Methane emissions comprise approximately 6 percent of overall greenhouse gas emissions over this time period.

The next portion of Table 1 (Lines 29 through 37) includes anthropogenic activities that generate nitrous oxide emissions. This gas is sometimes called "laughing gas" and should not be confused with a class of conventional air pollutants called "oxides of nitrogen". The major sources of nitrous oxide emissions are agricultural activities and mobile source fuel combustion. Emissions of nitrous oxide produce approximately 7 percent of overall GHG emissions over this time period.

A class of gases called "high global warming potential gases" makes up the final set of gases (Lines 38 through 41) that contribute to global warming. Major categories within this set include various gases used in industrial applications to replace gases associated with ozone depletion over the Polar Regions of the Earth, and SF_6, which is used as insulating materials in electricity transmission and distribution.

These high global warming potential gases comprise a small percentage of overall greenhouse gas emissions over this time period, although the estimated emissions are difficult to quantify and are thus less certain than other emissions categories. High global warming potential gases, although small in magnitude, constitute the greatest rate of growth in GHG emissions.

Table 1 Version: 6/8/2005

	Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1	Carbon Dioxide (Gross)	322.8	316.2	322.1	315.4	332.9	317.7	321.1	331.9	347.2	356.6	370.4	371.3	360.2
2	Fossil Fuel Combustion	311.8	305.6	310.8	305.9	321.5	306.1	309.3	319.8	336.8	345.6	358.5	357.8	348.9
3	Residential	29.0	29.5	27.8	28.4	29.2	26.6	26.6	26.3	30.7	31.8	29.6	28.2	24.8
4	Commercial	13.8	13.4	11.1	11.0	11.6	11.1	11.0	11.2	16.3	21.4	17.5	11.5	15.5
5	Industrial	68.2	66.4	62.9	65.4	66.8	64.0	70.1	74.5	77.2	72.1	76.8	79.5	74.6
6	Transportation	161.1	156.7	161.9	158.9	163.9	166.2	167.4	170.8	173.3	176.3	181.7	181.6	189.9
7	Electricity Generation (In State)	38.7	39.0	46.6	41.7	49.3	37.7	33.6	36.5	39.3	43.3	52.0	56.3	43.5
8	No End Use Specified	1.1	0.6	0.5	0.6	0.6	0.5	0.5	0.4	-0.1	0.6	0.9	0.7	0.7
9	Cement Production	4.6	4.3	3.8	4.4	5.1	5.0	5.3	5.5	5.4	5.6	5.9	5.6	6.2
10	Lime Production	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
11	Limestone & Dolomite Consumption	0.2	0.1	0.1	0.1	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2
12	Soda Ash Consumption	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
13	Carbon Dioxide Consumption	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
14	Waste Combustion	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
15	Land Use Change & Forestry Emissions	5.5	5.6	6.8	4.4	5.6	5.8	5.8	5.9	4.1	4.6	5.2	7.2	4.3
16	*Land Use Change & Forestry Sinks*	*(22.7)*	*(22.3)*	*(21.9)*	*(21.5)*	*(21.1)*	*(20.7)*	*(20.3)*	*(19.9)*	*(19.5)*	*(19.1)*	*(19.6)*	*(19.9)*	*(20.3)*
17	Carbon Dioxide (Net)	300.1	293.9	300.2	293.9	311.9	297.0	300.8	312.0	327.6	337.5	350.8	351.3	339.9
18	Methane (CH_4)	31.1	31.1	31.1	30.1	30.8	30.9	30.2	30.5	30.1	30.7	30.3	30.9	31.3
19	Petroleum & Natural Gas Supply System	1.3	1.2	1.2	1.1	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9
20	Natural Gas Supply System	3.3	3.2	3.1	2.9	2.8	2.7	2.5	2.4	2.2	2.0	1.9	1.9	1.9
21	Landfills	10.0	10.0	9.9	9.9	9.8	9.8	9.8	9.9	9.9	9.9	9.9	10.0	10.1
22	Enteric Fermentation	8.2	7.9	8.1	7.2	7.8	7.9	7.4	7.5	7.5	7.8	7.3	7.7	7.7
23	Manure Management	3.6	4.2	4.3	4.4	4.7	5.0	5.0	5.3	5.3	5.7	5.9	6.1	6.3
24	Flooded Rice Fields	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.5	0.5
25	Burning Ag Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
26	Wastewater Treatment	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9
27	Mobile Source Combustion	1.3	1.3	1.2	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.7
28	Stationary Source Combustion	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
29	Nitrous Oxide (N_2O)	32.3	30.0	30.1	31.0	29.6	31.5	30.4	28.5	28.9	29.1	31.0	30.4	33.6
30	Nitric Acid Production	0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.1	0.2
31	Waste Combustion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Agricultural Soil Management	14.0	12.5	12.8	13.8	13.1	14.9	14.5	13.1	13.5	13.8	15.3	14.8	18.6
33	Manure Management	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.9	0.9	0.9
34	Burning Ag Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
35	Wastewater	0.9	0.8	0.8	0.9	0.8	0.8	0.8	0.9	1.0	1.0	0.7	1.0	0.9
36	Mobile Source Combustion	15.7	15.0	14.9	14.9	14.3	14.3	13.7	13.1	13.1	12.9	13.4	13.2	12.6
37	Stationary Source Combustion	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
38	High GWP Gases (HFCs, PFCs & SF_6)	9.9	10.0	10.3	10.5	10.8	11.0	13.2	14.3	16.7	16.7	17.0	16.1	17.3
39	Substitution of Ozone-Depleting Substances	6.9	7.2	7.5	7.8	8.1	8.4	10.3	11.6	14.1	14.1	14.9	14.3	15.5
40	Semiconductor Manufacture	0.4	0.4	0.4	0.5	0.5	0.7	0.7	0.8	0.9	0.9	0.8	0.5	0.5
41	Electricity Transmission & Distribution (SF_6)	2.7	2.5	2.4	2.2	2.2	2.0	2.2	2.0	1.7	1.6	1.4	1.2	1.2
42	Gross California Emissions (w/o Electric Imports)	396.1	387.3	393.5	386.9	404.2	391.1	394.9	405.3	422.8	433.0	448.7	448.7	442.4
43	*Land Use Change & Forestry Sinks*	*(22.7)*	*(22.3)*	*(21.9)*	*(21.5)*	*(21.1)*	*(20.7)*	*(20.3)*	*(19.9)*	*(19.5)*	*(19.1)*	*(19.6)*	*(19.9)*	*(20.3)*
44	Net Emissions (w/o Electric Imports)	373.4	365.0	371.7	365.5	383.1	370.4	374.6	385.4	403.3	413.9	429.1	428.7	422.1
45	Imported Electricity	43.3	43.1	43.0	40.8	43.2	38.5	40.6	47.0	52.9	51.7	40.5	47.4	51.7
46	Gross California Emissions with Electricity Imports	439.4	430.4	436.6	427.8	447.3	429.6	435.4	452.2	475.7	484.7	489.2	496.1	494.1
47	Net California Emissions with Electricity Imports	416.7	408.1	414.7	406.3	426.3	408.9	415.1	432.3	456.2	465.6	469.6	476.1	473.8
48	International Bunker Carbon Dioxide Emissions	39.9	34.6	28.0	27.9	32.4	35.8	35.4	27.0	26.8	30.3	33.8	31.8	31.8

Gross carbon dioxide emissions from fossil fuel combustion comprised 81 percent of total greenhouse gas emissions in 2002, the largest component of the inventory. Non-fossil fuel carbon dioxide emissions contributed another 2.3 percent.

Land use and forestry changes cause carbon dioxide atmospheric concentrations to increase when carbon-consuming plants are removed or stop growing. These changes cause carbon dioxide concentrations to decrease when carbon-consuming plants are added to the landscape. When these activities lead to a net reduction they are called carbon sinks.

Land use and forestry changes from anthropogenic activities have caused carbon dioxide concentrations to increase in some years and to decrease in others. The carbon released in the form of carbon dioxide from burning wood waste from land uses and forestry practices are included as emissions in the greenhouse gas inventory, Line 15. The carbon taken out of the atmosphere in the form of increased acreage of growing trees is also included as sinks of carbon dioxide from anthropogenic activities, Line 16 (and Line 43).

Line 42 is labeled “Gross California Emissions.” It is the sum of Lines 1, 18, 29, and 38. Total sinks are repeated on Line 43 for clarity. Net carbon dioxide emissions are shown in Line 44. These are obtained by subtracting Line 43 from Line 1.

A significant portion of the greenhouse gas emissions that occur to meet the needs of California’s economy comes from fuel combusted in out-of-state power plants that provide electrical energy to California, including two coal-fired power plants owned by California utilities. These emissions are shown on a separate line to avoid double counting. The carbon emissions associated with importing electricity to California are shown on line 45 and are not part of the California greenhouse gas inventory, but are shown for information purposes.

Line 46 is the sum of gross GHG emissions from Line 42 plus carbon dioxide from imported electricity from Line 45. Line 47 is Line 46 minus carbon dioxide sinks from Line 43. Line 48 shows international bunker fuels, made up of international use of jet fuel and marine vessel use of residual oil and distillate. These are not part of the California greenhouse inventory, and are shown for information purposes, similar to imported electricity.

Appendix A contains documentation of the methods used to prepare the California greenhouse inventory and a more detailed breakdown of the values in Table 1.

Future Greenhouse Gas Inventory Improvements

One major category of GHG inventory improvement which staff recommends is to use a more current estimate of global warming potential weighting factors (GWPs) for the non-carbon dioxide greenhouse gas emissions when they become approved for use by the International Panel on Climate Change (IPCC). Values used in this inventory are a bit stale, as they are based upon values approved for use by the IPCC in 1996. Newer GWPS were developed in 2001, but they have not yet approved for use. The other major category of GHG inventory improvements which staff recommends is using more recent energy flow data and more local activity data.

Global Warming Potential Weighting Factors for Non-Carbon Dioxide Gases

The current IPCC guidance is to use global warming potentials (GWP) from the Second Assessment Report[35] (SAR, 1996 vintage), since the Third Assessment Report (TAR, 2001 vintage) values have yet to be approved. For methane, the SAR value is 21, and the TAR value is 23 (+0.1 percent). For nitrous oxide, the SAR value is 310, and the TAR value is 296 (-4.5 percent).

Given the relative magnitude of carbon dioxide and other greenhouse gas emissions attributable to California using either the SAR or TAR values, the choice of SAR or TAR has little impact on California's greenhouse gas emissions. If TAR global warming potentials are used, methane emissions reported in 2002 would be 31.4 million metric tons CO_2-equivalent ($MMTCO_2E$), rather than the SAR value of 31.3 $MMTCO_2E$. Correspondingly, if TAR global warming potentials are used, nitrous oxide emissions reported in 2002 would be 33.0 $MMTCO_2E$, rather than the SAR value of 33.6 $MMTCO_2E$. These differences are small in a total inventory of over 500 $MMTCO_2E$.

Data Improvements or Refinements

During the process of developing this GHG update, Energy Commission staff identified the following areas where improvement is needed during the next inventory update.

- Use more current activity data.

  The most current complete data set for fossil fuel use in California is for 2002. Since over 80 percent of the California GHG inventory is from fossil fuel combustion, it is not possible to report complete GHG data for more current years at this time. These data should be updated as soon as more current data become available.

- Perform a more detailed review of industrial uses of fossil fuels to classify when they are used as fuel versus their use as a process input (and therefore not released into the atmosphere at that step in their usage chain).

  As discussed above for Line 5, petroleum and natural gas are sometimes used in an industrial process rather than combusted as a fuel in an industrial facility. In some cases, feedstock use leads to carbon emissions, but in most cases the carbon in the fuel is transformed at the industrial site into the product of the industrial operation. In this case, no carbon emissions occur at this point in the product's production and use cycle, and there are no carbon dioxide emissions to document. Carbon dioxide emissions may occur when the object being produced is used in an end use application. This is the point in the usage chain where carbon dioxide emissions should be counted in the greenhouse gas emissions inventory.

  The 1990-1999 California GHG emissions inventory used national data to estimate the amounts of petroleum and natural gas that were used as industrial process feedstocks rather than burned as fuels. This assumes that California's industrial sector exactly matches the national average of industrial activities.

  In the current inventory, staff examined each subcategory of industrial use and judged whether or not the petroleum or natural gas was used as a feedstock or as a fuel. If they were judged to be used as a feedstock, then the national average values were used. If they were judged to be used as a fuel, staff used the normal calculation process and assumed that the emissions would occur on the site of the industrial process. In addition, methane generation at refineries was assumed to release carbon dioxide at the refinery. Differences between approaches are minor.

- Industrial wastewater emissions occur from processing fruits and vegetables; red meat and poultry; and pulp and paper. Methane and nitrous oxide emissions from these activities are not yet included in the California inventory, and should be added in future updates.

  California produces much of this country's fruits, vegetables, red meat, poultry, and pulp and paper. These products all involve industrial waste water, which should be estimated and added to the California GHG inventory. The EPA guidance document[36] recommends that emissions be estimated for these industrial sources (see page 14.4-5). However, since we do not yet have data on the quantity of waste water generated by these activities, staff was unable to estimate methane or nitrous oxide emissions from waste water used to produce these products.

- Landfill methane emissions should be reviewed in more detail. Values look low compared to 1990-1999 inventory. Some have reported higher values. These discrepancies need to be resolved.

  The EPA guidance document[37] recommends obtaining state-level data on the volume of wastes stored in large landfills (that is, greater than 1.1 million tons of waste in place), and small landfills (less than 1.1 million tons of waste in place), over the previous 30 years to calculate methane emissions from municipal waste landfills (see page 13.4-2). Lacking that, the document recommends using state-level volumes disposed at landfills. Lacking that, the document recommends using state-level population data and national average per-capita landfill rates to calculate emissions.

  The 1990 to 1999 California GHG emissions inventory used state-level data on volumes of waste disposed at California landfills from 1990 to 1999, and national data to estimate volumes of waste from 1960 to 1989, and the amount going to small versus large landfills for 1990 to 1999. Estimates were made for methane recovery in landfill gas-to-energy facilities, flares, and oxidation. Emissions were about 17 $MMTCO_2E$ in 1990, and decreased to about 13 $MMTCO_2E$ in 1999 because methane recovery grew faster than waste emissions.

  The current California GHG inventory was developed from emissions data obtained from local air pollution control agencies via the CARB. It is more of a "bottoms up" approach based upon a facility-by-facility assessment conducted by the local air districts. Emissions were estimated at about 10 $MMTCO_2E$ in 1990 and remained essentially flat over the entire 1990 to 2002 time period.

  These differences amount to a little over 1 percent of total California GHG emissions. They should be studied further to determine the best approach.

- Develop California-specific data for SF_6 emissions from electric utilities.

  Sulfur hexafluoride emissions were estimated using national emissions data and pro-rating state electric energy production to national values. However, California utilities have been actively involved in identifying and implementing methods to reduce these emissions and reducing associated maintenance costs. Individual electric utility companies in California should be contacted to obtain actual state-level data, if available. Since utilities have apparently not tracked their sulfur hexafluoride as an individual maintenance cost, it may not be possible to use utility-specific data for the entire 1990 to 2002 time period.

- Develop California-specific emissions factors for emissions of methane and nitrous oxide from manure management.

Emissions calculations are based upon national data for animal characteristics, including percentage of dairy versus meat cattle, nitrogen production per head of animal, animal mass, etc. These data should be updated with state-specific values and methods of animal management.

- Develop California-specific emissions factors for enteric fermentation from animal husbandry.

  Studies indicate that the currently accepted emissions factors overstate emissions of methane emissions from cattle processing their feed by a wide margin. The CARB is developing new emissions factors for regulatory purposes and these will be included in future updates.

APPENDIX A

DETAILED DOCUMENTATION OF CALIFORNIA GREENHOUSE GAS EMISSIONS

Units: Million Metric Tons of Carbon Dioxide-Equivalent

Notes:

1. Values are shown for 1990 to 2003 when available. Year 2003 values are shown for information purposes but are not shown in the main report because values were not available for all end use sectors and sub-sectors.

2. Where possible, values in the following table that are summed to obtain subtotals are shown as right justified to facilitate identification by the reader. This is not possible for all levels of subtotaling.

CALCULATION METHODOLOGY

This appendix includes detailed documentation of methods used to construct the updated California GHG emissions inventory. First, a discussion of the methodology is provided. Next, a detailed table of California GHG emissions is provided. This detailed table is summarized in Table 1 of the main body of this paper. Line numbers included in the text below refer to rows in Table 1, unless otherwise stated.

Carbon Dioxide Emissions

Carbon dioxide emissions occur largely from combustion of fossil fuels. In 2002, fossil fuel combustion accounted for 96.6 percent of gross carbon dioxide emissions. Other carbon dioxide emissions sources included cement and lime production; limestone and dolomite consumption; soda ash, carbon dioxide and waste combustion; and finally, changes in land use and forestry operations.

Carbon Dioxide Emissions from Fossil Fuel Combustion

Fossil fuels used in California include natural gas, petroleum [including liquefied petroleum gas (LPG), motor gasoline, kerosene, distillate oil, residual oil, petroleum coke, lubricants, asphalt, and others], and small amounts of coal. Biomass is also used as a fuel in some applications, but these emissions are excluded because the net amount of carbon dioxide released is zero when averaged over the life of the biomass itself. For example, a tree takes as much carbon dioxide out of the air as it releases into the air when it is burned. Any fuel used to plant, cultivate, and harvest the tree is included in the appropriate fuel use category.

Under contract by the Energy Commission's Public Interest Energy Research (PIER) Program, Lawrence Berkeley National Laboratory evaluated fossil fuel supplies and uses in California and developed a balance between them under contract by the PIER Program. Their work led to a document titled California Energy Balances Report,[38] (*Energy Balance)* and included a database of energy consumption which can be expressed in trillion British Thermal Units (trillion BTUs, or TBtus).

The *Energy Balance* was developed using data from the EIA, supplemented with data from the Energy Commission. Much of the data used in the *Energy Balance* was obtained from the same EIA data sources used in the 1990-1999 greenhouse gas emissions inventory and is thus consistent with it. In some cases, EIA revised and updated their data and these changes are reflected in the *Energy Balance* and in the updated greenhouse gas emissions inventory.

Energy Commission data were used to provide more detailed resolution of fuel use by end-use sector. One area of major improvement over the 1990-1999 greenhouse gas inventory is the treatment of electricity generation fuel use. The earlier GHG inventory reported electricity fuel used in the industrial sector unless the electric facility was owned by an electric utility company. The current GHG inventory identifies all fuel used to generate electricity as “Electricity Generation” regardless of the type of facility.

Fossil fuel carbon dioxide emissions are estimated by multiplying standardized emissions factors (EF) recommended by the EPA in their Emissions Inventory Improvement Program documentation[39] by the TBtu data from the *Energy Balance,* converting from carbon emissions to carbon dioxide emissions, and then using conversion factors to obtain results in million metric tons of carbon dioxide.

The equation typically used for carbon dioxide is:

CO_2 = Billion BTUs * Percent Oxidized * EF (lbs C per million BTU) * 0.9072 (converts short tons to metric tons) * 44/12 (converts lbs C to lbs CO_2) * 0.0005 (converts lbs to short tons) * 1000000 (expresses results in millions)

This result is expressed in million metric tons of carbon dioxide ($MMTCO_2$). Some manuscripts use the term teragrams rather than metric tons. One million metric tons equals one teragram (Tg).

The trillion BTUs (10^{12} BTUs, also expressed “TBTUs”) of fuel used in various end-use applications in California are shown in Appendix B. These data are obtained from the *Energy Balance.* Energy use data are listed in the same series order as the California greenhouse gas emissions inventory. For some fuels, data are provided for fairly focused categories of end use. Fuels with insufficient data to report detailed end-uses are reported as “Non-specified.”

Emissions are calculated for each fuel using fuel-specific values for percent oxidized values and carbon content as shown in Table A-1 (for fuels which have values that do not change from year-to-year) and Table A-2 (for fuels which values that change from year-to-year). These values were obtained from the EPA[40] and are consistent with the International Panel on Global Climate Change protocol.

Carbon dioxide emissions are calculated individually for each fuel and end-use sector, and are then totaled to get sums for carbon dioxide and for each end-use sector, such as residential, commercial, and so forth.

This method is the same as used in the 1990-1999 GHG emissions inventory with new data as available (except imported electricity, as explained below). See Appendix B for energy use rates used to estimate carbon dioxide emissions for each end use category and sub-category.

Line 1—Carbon Dioxide (Gross)
This line represents the sum of all carbon dioxide emissions, including fossil fuels, non-fossil fuel carbon dioxide emissions, and land use and forestry activities that increase carbon dioxide emissions.

Line 2—Fossil Fuel Combustion Totals
This line is the sum of fossil fuel combustion, Lines 3 through 8.

Line 3—Residential Carbon Dioxide Emissions
In California, residential carbon dioxide emissions are produced from the combustion of natural gas, LPG, kerosene, and distillate fuel.

Line 4—Commercial Carbon Dioxide Emissions
Commercial carbon dioxide emissions are produced from the combustion of coal, petroleum, and natural gas. Only small quantities of coal and petroleum fuels are used in California, so natural gas comprises the majority of the fuel used. Most commercial petroleum fuel use is gasoline or distillate, with small amounts of residual oil and LPG. Natural gas is used in applications that range from education through non-specified services.

Line 5—Industrial Carbon Dioxide Emissions
Industrial carbon dioxide emissions are produced from the combustion and feedstock uses of coal, petroleum, and natural gas. This end-use sector uses only a small amount of coal, moderate amounts of petroleum, and relatively large amounts of natural gas. However, even though this sector uses much more natural gas than petroleum (compare Appendix B, Line 48 to Appendix B, line 105), resulting carbon dioxide emissions for natural gas and petroleum are similar in magnitude.

This results because petroleum has greater carbon intensity per unit of energy and because much of the industrial petroleum use is in feedstock applications (such as asphalt manufacturing) rather than fuel applications (such as making steam for an onsite industrial process). Feedstock applications may or may not cause direct emissions because the carbon may be stored rather than emitted to the atmosphere. For some feedstock applications, the carbon is used in a product that is burned at another step in the product cycle, and that is where the carbon emissions are accounted for in the normal inventory protocol to avoid double counting.

Industrial uses of coal, petroleum, and natural gas must be adjusted to account for these feedstock uses and associated carbon storage. These feedstocks can either be stored on a long-term basis (such as in asphalt pavement) or a short-term basis but later emitted (such as natural gas used as a feedstock to make hydrogen in a refinery).

In the first case, the carbon associated with the feedstock is locked into the pavement and assumed to never be emitted and the computed emissions are zero. In the second case, the carbon is released during operation of a steam reformer located at or near a refinery and emitted after separating the hydrogen from the carbon.

In summary, it is necessary to subtract the amount of feedstock used and stored from the amount used as a fuel at the industrial facility.

The approach requires: (1) identification of the percent of each industrial fuel that is used as a feedstock, not a fuel, and (2) the percent of the feedstock that is stored rather than emitted in the associated industrial process.

The EPA guidance document indicates that state-level data should be used if available. However, if state-level data are not available, national data can be used. The 1990-1999 California GHG inventory used national data.[41] However, since the *Energy Balance* now provides much more state-level detail for industrial uses of coal, petroleum, and natural gas, it is no longer necessary to assume that these national factors apply in California for every industrial use.

A more accurate assessment is possible due to the increased level of industrial uses of fossil fuels provided by the *Energy Balance*. In the new greenhouse gas inventory, each industrial subcategory of end-use was examined individually and the most likely use of the fossil fuel was estimated by the category name. If it was most likely that the fuel was burned onsite for process heat or steam, then all of the fossil fuel was assumed to be burned on site. If it was most likely that the fossil fuel was used as a process input, the national average storage factor was assumed to apply to that subcategory.

The percent feedstock use and storage factor were both assumed to be zero if the subcategory appeared to be a fuel use. Otherwise, the inventory assessment uses the same national numbers as the 1990-1999 inventory. There is room for improvement with either method of assessing the industrial category of fossil fuel emissions.

To determine the degree to which this change impacts the estimated industrial sector carbon dioxide emissions, they were calculated each way. The results are similar using either approach. For example, for natural gas industrial emissions in 1999, the 1990-1999 method yielded a value of 33.4 $MMTCO_2E$ and the current method yields a value of 34.3 $MMTCO_2E$. The new approach was chosen because state-level energy data were available and the national values did not seem appropriate for some of the industrial subcategories. Using national average data for feedstock use of fossil fuels is equivalent to assuming California has exactly the same industries as all 49 other states.

Industrial fossil fuel use data were available for all each year for all fuels except liquefied petroleum gas. For this fuel, the average of 1990 to 2001 fuel usage rates was assumed for 2002.

Line 6—Transportation
Carbon dioxide emissions from the transportation sector constitute the single largest category of California's GHG emissions: 190 $MMTCO_2E$ in 2002. Motor gasoline is the single largest subcategory of transportation emissions at 138 $MMTCO_2E$ in 2002. Jet fuel is the next largest subcategory at 26 $MMTCO_2E$ in 2002.

Motor gasoline is used in light-duty vehicles in a wide variety of applications, although most is used in privately owned vehicles. Jet fuel is used in domestic aviation, international aviation, and military aviation. Emissions values do not include international aviation (or marine) uses.

Greenhouse gas emissions inventory guidance[42] is to identify international jet and marine fuel uses and report their emissions separately from corresponding domestic uses, if sufficient data are available. These are called "international bunker fuels." This is a bit of a misnomer because the traditional use of the term "bunker fuels" is for marine fuel use, not jet aircraft fuel use. Bunker fuels are heavy, often require heating to flow, and are not used in jet aircraft. However, the term "international bunker fuels" is used in GHG emissions inventories to mean distillate and residual fuels used for international business.

The California GHG inventory includes jet fuel, and residual and distillate oils used as domestic fuels. It excludes international jet fuel and marine residual and distillate fuel uses, but values are reported on separate lines for comparison purposes. Previous California GHG inventories were not able to separate out all international and domestic aviation and marine fuel uses. Thus, reported GHG emissions values are lower for the entire 1990 to 2002 period.

In 2002, international aviation accounted for approximately 40 percent of California's total reported jet fuel use and international marine fuel use accounted for 94 percent of California's residual oil use and less than 2 percent of its distillate fuel use.

Transportation fossil fuel use data were available for all each year for all fuels except liquefied petroleum gas. For this fuel, the average of 1990 to 2001 fuel usage rates was assumed for 2002.

Line 7—Electricity Generation (In-State)
Carbon dioxide emissions from electricity generation are produced from the combustion of fossil fuels. Due to environmental and other restrictions, most fossil fuel used to produce electricity in California is natural gas (approximately 43 percent of the total electrical energy produced for use in California in 2001, and 33 percent in 2002).

The 1990-1999 GHG emissions inventory identified utility-owned electricity production, but electricity produced by other entities was reported as a part of industrial emissions. The *Energy Balance* identifies industrial, commercial, and electrical combined heat and power fuel uses, as well as independent power producers, utility-owned electricity generation and non-specified electricity generation. Each is identified as a separate fuel used to generate electricity, as shown in Appendix B, lines 175 to 185. This is a major improvement in the tracking of electricity generation and industrial carbon dioxide emissions for the California GHG emissions inventory.

Line 45—Imported Electricity

During the 1990 to 2002 period, California imported 22 to 32 percent of its electric energy from nearby states. The method of generating this imported electric energy ranges from coal-fired power plants to nuclear and hydroelectric power plants. Electricity generated from burning coal releases relatively large amounts of GHG emissions while electricity generated from nuclear and hydroelectric power plants do not emit greenhouse gases.

Due to the nature of imported electrical energy transactions, it is oftentimes not possible to determine the type of facility and associated carbon-based fuel used to generate the imported electricity. However, to estimate carbon emissions from imported electricity, it is necessary to estimate the source(s) of electricity and associated rates of carbon emissions per gigawatt-hour of imported electricity. Thus, an estimate must be made of the fuel used to generate this portion of the imported electricity.

The EPA GHG emissions inventory guidance document[43] recommends that states estimate emissions from net imports of electricity. California does sometimes export a small amount of electricity, but nearly all of the transactions are imports. The GHG inventory of in-state emissions could be reduced to account for the electricity exported from California, but the amount is small enough to ignore this factor.

To estimate the carbon dioxide emissions from Pacific Northwest electricity imports, we assume 20 percent was generated by coal and 80 percent from hydroelectricity. Correspondingly, for electricity from the Pacific Southwest we assume 74 percent coal and 26 percent hydroelectricity. These values were adopted for use in the *1994 Electricity Report* for the 1994 to 1999 period.

This report assumes that they apply for the entire1990 to 2000 time period. Additional electrical energy is also generated from two out-of-state coal-fired power plants[44] owned by California electric utilities. The fuel used to generate this energy is known to be coal, and there is no need to estimate its fuel source. These emissions are calculated separately and the results added to the values estimated for the Pacific Northwest and Pacific Southwest to obtain overall carbon emissions from imported electricity.

To estimate carbon dioxide emissions from out-of-state electricity generation for 2001 and later years, the Energy Commission's Electricity Office uses data on reported electrical energy transactions to estimate the percentage of energy from coal, natural gas, oil, nuclear, and other sources. These percentages were used for

2001 and 2002 and will be used for more current years when the inventory is further updated in the future.

The Energy Commission publishes a table of electrical energy generation from utility-owned and non-utility owned power plants with gigawatt-hours (GWh) of electrical energy production intended for use in California shown by fuel type. The table also shows overall gigawatt imports from the Pacific Northwest and Pacific Southwest.

This table is used, along with the percentage data above, to derive total GWh of imported electrical energy by fuel type. To convert electrical energy into its thermal (BTU) equivalent, staff assumed a thermal conversion rate of 10,000 BTU/kWh. This is an approximate value which could be refined, but this step is deemed not necessary due to the uncertainty of other assumptions needed to estimate imported energy levels by type of fuel.

After obtaining BTU estimates per year for each fuel type using the method described above, carbon dioxide emissions are calculated in the same manner as other sources of fossil fuel emissions for Lines 2 through 8. Appendix C discusses two other approaches for estimating carbon dioxide emissions from electricity imported to California.

Line 8—No End-Use Specified

The *Energy Balance* identified a small amount of natural gas and liquefied petroleum gas use that could not be associated with a specific end-use. The associated carbon dioxide emissions are listed on Line 8.

Carbon Dioxide Emissions from Non-Fossil Fuel Emissions Sources

Some human activities release carbon dioxide gases without burning fuel. These sources contribute a modest portion of gross carbon dioxide emissions (2.3 percent in 2002).

Line 9—Cement Production

Cement production involves a chemical conversion process that releases carbon dioxide gas as limestone is heated in a kiln to produce lime. The resulting clinker is further processed to produce cement.

Quantities of masonry cement and Portland cement produced in California were obtained from U.S. Geological Survey (USGS) Minerals Yearbook (various years): Table 1, Masonry & Portland Cement Production. Masonry cement and Portland cements were added to determine total cement manufactured, with the bulk of production being Portland cement. See Table A-3 for Masonry and Portland cement production in California.

Clinker production was multiplied by 0.65 to obtain the lime content of the clinker and this value was multiplied by 44/56[45] to convert to carbon dioxide. This value was multiplied by 1.02 to account for clinker dust.

This method is the same as used in the 1990-1999 GHG emissions inventory but with updated or revised data from the USGS Minerals Yearbook (various years) where available.

Line 10—Lime Production

Lime is used in a wide variety of applications, including construction, pulp and paper manufacturing, and sewage treatment. The analysis assumes that California's lime production matches its lime use. Lime production leads to carbon dioxide emissions in a process similar to cement production. Limestone is heated in a kiln to produce lime, releasing carbon dioxide.

Lime production data for California are obtained from the USGS web site [http://minerals.usgs.gov/minerals]. California values are available from USGS for 1990 to 1998 but are withheld for later years to avoid disclosing company proprietary data. Production decreased from 1990 to 1993, but increased thereafter. Values for the 1999 to 2002 time period were extrapolated from 1993 to 1998 values.

California lime production data are shown in Table A-3. Although this is an increasing trend, there is a decreasing number of lime producing facilities. This explains why the lime production data are withheld after 1998. Future inventory methods may not be able to rely upon USGS for California lime production data.

Carbon dioxide emissions are calculated by multiplying lime production by 44/56, the ratio of molecular weight of carbon dioxide to lime (CaO).

This method is the same as used in the 1990-1999 GHG emissions inventory with new or revised data as available.

Line 11—Limestone & Dolomite Consumption

Some uses of limestone and dolomite (both are called "limestone" in mineral industry terms) produce Carbon dioxide emissions,[46] but others do not. No data are available to differentiate limestone and dolomite uses in California that emit carbon dioxide from those that do not. It is necessary to assume that the national percentage of uses applies equally to California and obtain California's portion by ratio.

Nationwide and California limestone and dolomite consumption are both available from the USGS. Nationwide carbon dioxide emissions were obtained from the United States GHG inventory. California emissions were obtained by adding limestone and dolomite production and obtaining emissions by ratio. This assumes that the same mix of carbon dioxide producing uses and non-carbon dioxide producing emissions is the same, including flue gas desulfurization, which is not likely. However, no better method is available to estimate these emissions. The small magnitude of these emissions means that further refinement of this data does not appear to be warranted at this time.

This method is the same as used in the 1990-1999 greenhouse gas emissions inventory with new or revised data as available.

Line 12—Soda Ash Consumption
Carbon dioxide emissions occur when soda ash (Na_2CO_3) is used to make glass and soap. Payroll data for California and nationwide were used to estimate the magnitude of carbon dioxide released from these activities, using the ratio of California to national payrolls to determine California emissions. California's glass-making payroll was 8.5 percent of the national glass-making payroll in 1996, and California's soap-making payroll was 7.6 percent of the national soap-making payroll in 1996. An average of 8.0 percent was used to estimate the California carbon dioxide emissions from glass- and soap-making activities.

This method is the same as used in the 1990-1999 greenhouse gas emissions inventory with new or revised data as available. The payroll data were not updated.

Line 13—Carbon Dioxide Consumption
Nationally, carbon dioxide is emitted from natural gas wells, as a by-product of chemical production, and when separating crude oil and natural gas. It is also used for a wide variety of activities, including chemical production, food processing, and consumption of carbonated beverages.

California's carbon dioxide emissions from carbon dioxide consumption was scaled from national emissions by using the ratio of California's carbon dioxide production capacity to the national production capacity from year to year.

This method is the same as used in the 1990-1999 GHG emissions inventory with new or revised data used (as available) for the national carbon dioxide emissions from carbon dioxide use.

Line 14—Waste Combustion
Carbon dioxide and nitrous oxide emissions to the atmosphere occur when municipal solid waste (MSW) is combusted to make electricity. A portion of the waste stream is biogenic, and these carbon dioxide emissions are not counted because the carbon is recycled during the growth period of the biogenic materials. Another portion of the waste stream is made from plastic, synthetic rubber, and synthetic fibers, and this portion is counted because they are derived from fossil fuels. The nitrous oxide emissions (Line 31) are documented below.

There are three MSW facilities in California: Commerce Refuse-to-Energy, Southeast Resource Recovery, and Ogden Martin Systems of Stanislaus, Inc. Representatives of each were contacted to obtain annual tons of MSW process for

1990 through 2002. These values were multiplied by 0.1104 tons of carbon per ton of MSW for plastics, 0.0174 tons of carbon per ton of MSW for synthetic rubber, and 0.0343 tons of carbon per ton of MSW. These emissions factors are national average values derived by the EPA. Results are summed and converted to million metric tons of carbon dioxide to get total carbon dioxide emissions from MSW.

This method is updated from the 1990-1999 GHG emissions inventory, with new emissions factors for waste stream constituents.[47]

Land Use Change & Forestry Overview

The 1990-1999 greenhouse gas emissions inventory estimated net carbon dioxide flux caused by changes in forest carbon stocks, changes in agricultural soil carbon stocks, and changes in yard trimming carbon stocks in landfills. Forested land in California was estimated based on California Department of Forestry's (CDF) five-year inventories, with the last inventory conducted in 1994. Therefore, all values for 1995 through 1999 were extrapolated from 1994 data. The forested land was categorized by ownership, use, and type of vegetation. Net changes in carbon stocks were tracked by modeling carbon flows related to tree growth, forest removals, and decomposition.

The current inventory approach uses a different approach to reflect methodology and quantification changes developed by Winrock International.[48] Changes in canopy cover were tracked through the California Land Cover Mapping and Monitoring Program (LCMMP) conducted by the CDF's Fire and Resource Assessment Program (FRAP).

LCMMP uses Landsat Thematic Mapper satellite imagery to map vegetation and changes over five-year periods. Carbon flux estimates are derived principally from Forest Inventory and Analysis (FIA) data. This approach allows for use of newer, California-specific information developed by the Energy Commission's Public Interest Energy Research Program.

Winrock provided emissions and removals of GHG by land-use sector for five-year intervals, i.e., between 1994 to 2000 for 84 percent of the forests and 42 percent of the rangelands. This was extrapolated to 100 percent of the area. Emissions and reductions for 1990 to 1994 were calculated using a FRAP analysis of a 7 percent reduction in forest land between 1953 and 1994. Emissions and reductions for 2002 (and for later years in future updates) are based on forecasted reductions in land by the federal Secretary of Agriculture. These values will be updated with future satellite imagery.

Agricultural acreages were based primarily on the National Resource Inventory (NRI) database and provided in discrete values for 1987, 1992, and 1997. Linear regression analysis was used to provide the values for 1990 to 1991, and 1993 to 1996. For 1998 to 2002, acreage data from the California Agricultural Statistics Services was used.

Carbon estimates for woody crops were made by Winrock based on above- and below-ground biomass, crop type (e.g. fruit, nut, and vineyard) and planting densities. Changes in agricultural soil carbon were not tracked because it was assumed agricultural land in California has been under cultivation long enough that changes in soil carbon stocks based on soil types are minimal. This may not be true for soils converted to viticulture and pasture, and this factor should be evaluated in future inventory updates.

Inventory categories were changed to reflect the new methodologies and baseline. However, because carbon changes cannot be detected from satellite and there is a lack of data on carbon densities of cropland, this inventory uses the 1990-1999 inventory method for land filling of lumber and urban wood waste and liming of soils as explained below.

<u>Line 15—Land Use Change & Forestry Emissions</u>
Winrock International tracked measurable decreases in canopy cover and the resulting decreases in carbon stocks (carbon emissions) separately from measurable increases in canopy cover (carbon storage). Decreases in carbon stocks (gross and net changes) varied by the cause of the change. Fire and harvest were the dominant causes of emissions on forestlands, and fire was the cause of emissions on rangelands.

Field measurements by Winrock and literature sources indicated no changes in soil carbon with land use or management except in the conversion to some forms of agriculture. Therefore, emission categories attributed to forest and agricultural soils were removed from this inventory.

Agricultural land was categorized by the types of crop grown – woody or non-woody. Total carbon stock was estimated based on area and crop type within the broad categories (fruit, nut, vineyard, berry, row crops, close crops, hay crops, and other).

Although there was an overall decrease in both woody and non-woody crops between 1987 and 1997, the inventory fluctuated between emissions and reductions for agricultural lands based on periods when woody crops increased and annual fluctuations in non-woody crop acreages. The apparent sudden, relatively large increase in reductions between 1997 and 1998 is an anomaly caused by a change in 1998 from NRI data to CASS data. 1990-1999 NRI data points were correlated to CASS acreages to determine they were within the uncertainty range.

<u>Liming of Soils</u>
Limestone and dolomite applied to agricultural soils degrades and releases carbon dioxide. The amount of carbon dioxide generated from using these soil treatments is estimated using the same method as used in the 1990-1999 inventory[49] with new data as needed.

Tonnage data of limestone and dolomite applied to California soils was obtained from the USGS's *Minerals Yearbook* for various years. These values were multiplied by the appropriate emissions factor (0.12 metric ton of carbon per metric ton of limestone, and 0.13 metric ton of carbon per metric ton of dolomite) and then converted to carbon dioxide by multiplying by the molecular weight ratio of carbon dioxide to carbon (44/12).

Line 16—Land Use Change & Forestry Sinks
Since satellite imagery only identifies measurable changes in canopy coverage during the time interval, carbon estimates are derived from FIA for forests and rangeland types with corresponding canopy closures. Tracking carbon stocks through satellite imagery measured changes in canopy overcomes problems with apparent changes in stocks due to land reclassification (e.g. moving acreage from private ownership to public ownership).

Agricultural sinks are estimated in the manner described above for Land Use Change and Forestry Emissions (Line 15).

Land filling of Lumber and Urban Wood Waste
The methods used for Lumber Disposal and Yard Trimming Disposal are the same as the 1990-1999 inventory with new data as needed.

Tonnage of lumber and urban yard trimmings disposed at landfills was obtained for 1990, 1999, and 2003 from the California Integrated Waste Management Board (CIWMB) surveys.[50] These surveys inventoried disposal in place (in situ). Therefore, the tonnage reported represented lumber and wood trimmings entering the landfill and not the municipal waste stream, as was assumed in the 1990-1999 inventory.[51]

An emissions factor of 0.30 metric tons of carbon per short ton of lumber, and 0.2082 tons of carbon per short ton of yard trimmings (grass, leaves, and branches) was applied to obtain annual estimates of carbon emissions from theses sources, and then converted to carbon dioxide by multiplying by the molecular weight ratio of carbon dioxide to carbon (44/12).

Line 17—Carbon Dioxide (Net)
This line is simply Line 1 minus line 16.

Methane Emissions

Methane (CH_4) emissions occur from operation of petroleum and natural gas supply systems, waste operations (landfills and wastewater treatment), agricultural operations (enteric fermentation, manure management, rice fields and agricultural burning), and from mobile and stationary fuel combustion. Methane emissions are converted into carbon dioxide equivalent emissions by multiplying the methane emissions in millions of metric tons by their 100-year GWP. For this inventory, we choose a GWP from the Second Assessment Report. The 100-year GWP for methane emissions is 21 times carbon dioxide emissions.

Line 18—Methane Total Emissions
This line is simply the sum of Lines 19 to 28.

Line 19—Petroleum & Natural Gas Supply System
The CARB provided the Energy Commission a data file of estimated methane emissions from area sources, including emissions from the petroleum and natural gas supply system. Data were provided only for 1990, 1995, 2000, and 2005. Values for intervening years were estimated by Energy Commission staff using interpolation. CARB documents their methodology for estimating emissions and provides criteria pollutant emissions data on their web site.[52]

Essentially, local air districts provide detailed field data to CARB, who summarizes it into statewide emissions. Methane emissions were estimated by CARB from total organic gas (TOG) emissions using a speciation profile[53] to determine the fraction of TOG comprised of methane. CARB provided data in tons/day. These were multiplied by 365 to convert to tons per year, and then by 0.9072 to convert from short tons to metric tons.

The new method uses data derived from local and regional analyses while the 1990-1999 GHG inventory method used national data. The new method combines emissions from both petroleum and natural gas extraction because they usually occur simultaneously in California due to the fact that natural gas is co-located and co-produced with crude oil. The new method is considered more representative of California's GHG emissions.

Petroleum and natural gas field operations release fugitive methane from oil/water separators, well operations, pumps and compressors, fittings and valves. Emissions also occur from operation of field reciprocating engines and from petroleum seeps. Petroleum marketing emissions occur from barge loading, lightering and ballasting and tanker loading.

Line 20—Natural Gas Supply System
Additional natural gas supply system methane emissions were obtained in the same manner explained above for the petroleum and natural gas supply system.

Some natural gas methane emissions are embedded in line 19, which includes emissions associated with producing both petroleum and natural gas. Additional natural gas methane emissions occur from wet gas stripping and field separation and from natural gas transmission losses. These are included in Line 20.

Line 21—Landfill Emissions
Methane emissions from California landfills were obtained in the same manner explained above for the petroleum supply system. These data are collected by local

air regulatory agencies and are considered a better representation of California GHG emissions.

Methane emissions from landfills include methane directly from landfills, weed abatement, grass and woodland wild fires, volatile organic waste disposal, and others.

Line 22—Enteric Fermentation

The amount of methane emissions from a domesticated animal depends on whether the animal is a ruminant,[54] the age and weight of the animal, and characteristics of feeding. Quantities of methane generated by ruminant animals are much greater than from non-ruminant animals, therefore, the focus of the quantification is on California's largest population of ruminant animals – cattle.

Although beef cattle populations have declined over the last 12 years, the dairy cattle population has increased significantly. California is the leading dairy state in the nation and dairy products are the state's number one agricultural commodity.

The 1990-1999 greenhouse gas emissions inventory[55] modeled each stage of the cattle population monthly from birth to slaughter. These monthly values are estimates and the method implies an accuracy that is not justified. Current studies indicate emission factors used in the inventory for California cattle may be much higher than what is actually produced with the industry's feeding regimes, and may overstate emissions. The CARB is developing new emissions factors for regulatory purposes, and these will be used in future updates to the inventory.

For this inventory, annual data for cattle and other agricultural livestock population (head) were taken from the California Agricultural Statistics Services (CASS). California specific emission factors from the 1990-1999 inventory were applied to these animal populations. This method increases the greenhouse gas emissions by approximately 10 percent within the category. The reader is referred to the 1990-1999 California GHG inventory,[56] pages 109 to 115 for an explanation of the method used to estimate these emissions.

Line 23—Manure Management

Methane emissions from livestock are generated through manure management systems. Emission factors for each type of livestock varies considerably since domestic livestock types vary from cattle to poultry.

The annual average animal populations were tabulated for:

1. Cattle (by type such as dairy or beef, and by size)
2. Swine (by type and by size)
3. Poultry (by type)
4. Sheep (by type)
5. Goats
6. Horses

Non-equine animal populations were obtained from California Livestock and Dairy Reports, and County Agricultural Commissioners' Data. Equine populations were estimated from 1999 data for horse populations, but are probably low because data is not collected for groups of fewer than 50 horses.

This method is the same as used in the 1990-1999 greenhouse gas emissions inventory with new or revised data as available.

Livestock manure produces methane by anaerobic decomposition of the manure for that fraction which is manages in a liquid storage system such as lagoons, ponds, tanks, or pits. Little or no methane is produced from methane managed as a solid or deposited on rangeland, etc. As ambient temperatures and moisture levels increase, methane emissions increase. Diets higher in energy content produce more methane.

Methane emissions are based on the quantity of volatile solids produced by livestock. This is determined from typical animal mass (TAM) and livestock populations. Methane emissions are estimated using emissions rates typical of each type of animal. These are adjusted by multiplying by a management factor to represent the percentage of emissions based upon type of management practice with zero representing practices that eliminate emissions and 1.0 representing practices that tend to maximize methane production.

Emission factors are based on national animal characteristics and will be updated to reflect California-specific values in future updates to the inventory. These factors range from 18 percent for cattle and goats to 48 percent for swine, with all values depending on type of animal and typical management practice.

<u>Line 24—Flooded Rice Fields</u>
Anaerobic decomposition of organic material by methanogenic bacteria in flooded rice fields produces methane. Some of the methane is oxidized, some is leached to ground water, and the remaining methane is diffused to the atmosphere, primarily through the rice plants.

Methane emissions from rice cultivation is small – representing less than 2 percent of the total methane emissions tracked for California. Although methane emissions increase significantly with ratoon or secondary crops grown from stubble, California does not grow ratoon rice.

The methane emission factor used was based on California studies and is lower than the average factor used by the EPA,[57] which represents rice soil temperatures and management practices throughout the eight rice-growing states. Acreage data for rice was obtained from the CASS.

This method is the same as used in the 1990-1999 greenhouse gas emissions inventory[58] with new or revised data as available. Essentially, annual acreage in hectares is multiplied by an emissions factor of 122 kilogram methane per hectare. This is multiplied by the global warming potential of 21 times carbon dioxide from the Second Assessment Report, and then divided to obtain million metric tons of carbon dioxide equivalent.

Line 25—Burning Agricultural Residues

Field burning is often used to dispose of pruned branches from crops and to dispose of unwanted crop components such as rice straw and field stubble. Agricultural burning is divided into two categories – crop residue burning and other agricultural waste burning. Crop residues are identified as non-woody or field residues, and woody or orchard/vineyard residues. The methodology for estimating GHG emissions from field burning of agricultural residues was based on the type and amount of residues produced, and the crop specific emission factors for methane (and nitrous oxide, see Line 34) released during combustion.

The inventory used California-specific factors for residue tonnages per crop acreage to determine total amounts of non-woody and woody residues. The percentage of the residues burned in the field was applied to these total amounts. Burning permits for other agricultural wastes were used to determine other non-crop agricultural burning.

California's crop residue profile differs from the national profile. Almonds, walnuts, wheat, barley, corn, and rice produce almost 98 percent of the field and woody crop residue burned in California. Adding cherry, apricot, and grape residue captures almost 100 percent of the agricultural residues burned in California, especially since grape acreages have increased substantially in recent years.

Changes in rice residue burning practices have decreased the amount of rice straw burned. California's cultivated rice acreage increased from 425,000 acres in 1990, to 533,000 acres in 2002, and rice residue tonnage has increased proportionally. However, the percent of rice residue burned has decreased from 99 percent before 2001, to 25 percent for 2001 and later years. This change is reflected in the inventory data.

Agricultural Crop Residues

Acreage data for all crops is taken from the annual Crop Reports compiled by the California County Agricultural Commissioners and from the California Agricultural Statistics Service. Emissions for this subcategory are estimated as described above.

Other Agricultural Waste Burning

Some other agricultural wastes produced and burned in California cannot be calculated based on crop acreages. These emissions are tracked through agricultural burning permits administered by individual air districts. The CARB maintains a database of agricultural emissions based on these permits and supplements these data with estimates where permit information is not available. The estimated Agricultural Crop Residues emissions based on acreages were subtracted from the emissions inventory provided by CARB to get a category we call "Other Agricultural Waste Burning."

Line 26—Wastewater Treatment

Anaerobic degradation of waste water produces methane emissions. These are calculated using California population data and appropriate generation rates and emissions factors from EPA. First, biochemical oxygen demand estimated by the "five-day test" (BOD_5) is estimated at 0.065 kilogram per capita per day. The anaerobic treatment fraction of BOD_5 is estimated at 16.25 percent, and the methane generation rate is assumed to be 0.6 kilograms of methane per kilogram of BOD_5. These factors are multiplied together to get the daily methane production rate and then multiplied by 365 to get a yearly value.

The methodology is the same as the 1990-1999 inventory, but the emission factors have been updated as of June 2003.

Line 27—Mobile Source Combustion

Methane emissions from mobile sources were obtained in the same manner explained above for the petroleum supply system, except the data was generated by CARB staff, not local air quality districts. This updated data source is similar to the overall approach used in the 1990-1999 inventory, except it uses CARB computer representation of the California fleet and is likely to be more detailed than the 1990-1999 approach.

The CARB provided data for gasoline vehicles (passenger cars, light-, medium-, and heavy-duty vehicles, boats, off-road vehicles, motorcycles, and others), for diesel vehicles (passenger cars, light-, medium-, and heavy-duty trucks), and for aviation.

Line 28—Stationary Source Combustion

Methane emissions from electricity combustion were developed in the following manner:

1. Obtain coal, oil, natural gas, and wood higher heating value (HHV) energy consumption data from the EIA for 1990 to 2002.

2. Multiply by 0.95 (for coal and oil) or by 0.90 (for natural gas and wood) to convert HHV to lower heating value (LHV).

3. Multiply by 1055 to convert from LHV BTUs to Joules.

4. Multiply by the appropriate emission factor (1.0 for natural gas and coal, 3.0 for petroleum, and 30.0 for wood) to convert from gigajoule to grams of methane.

5. Adjust to million metric tons.

6. Multiply by the global warming potential (21 for methane, second assessment report) to convert to CO_2-equivalents.

Methane emissions from other stationary source combustion were developed in the same manner explained above for the petroleum supply system, using data from the CARB. The CARB data were not used for electricity production because the data indicated that these values were only for cogeneration. The CARB values were lower, which is consistent with the fact that they did not include all electricity production.

Industrial stationary source methane emissions include gasoline and diesel used in a variety of equipment, including manufacturing and industrial sectors, food and agricultural processing, off-road equipment of all types, ships and commercial boats, and trains. Industrial methane emissions also include natural gas used in airport ground equipment, mineral processing, surface treatment, industrial equipment, and other industrial processes.

Commercial stationary source methane emissions include diesel and liquefied petroleum gas used in trains, asphalt paving and roofing, commercial lawn and garden equipment, boats, and others. Commercial methane emissions also include natural gas emissions from commercial water and space heating, cooking, and commercial off-road equipment. Another commercial activity is commercial cooking. Additional commercial methane emissions are associated with wood and paper processing.

Residential stationary source methane emissions include LPG and distillate oil combustion; natural gas used in water heating, space heating, and cooking. Residential methane emissions are also associated with wood combustion in wood stoves and fireplaces.

Other stationary source methane emissions include timber and brush fires, structure fires, and other processes not specified.

Nitrous Oxide Emissions

Nitrous Oxide (N_2O) emissions occur from nitric acid production, waste combustion, agricultural activities (agricultural soil management, manure management, and burning of agricultural residues), human sewage treatment, and from mobile and stationary fuel combustion. Nitrous oxide emissions are converted into carbon dioxide equivalent emissions by multiplying the N_2O emissions in millions of metric tons by their 100-year GWP. For this inventory, we choose a GWP from the Second Assessment Report. The GWP for nitrous oxide emissions is 310 times carbon dioxide emissions.

Line 29—Nitrous Oxide Total Emissions
This line is simply the sum of Lines 30 to 37.

Line 30—Nitric Acid Production
Nitric acid is used for producing synthetic fertilizer; making adipic acid, rocket propellant, and explosives; for treating stainless steel; for metal etching; and processing nuclear fuel. Nitrous oxide is a by-product of making nitric acid.

California's nitrous oxide emissions were estimated using the same method as the 1990-1999 GHG inventory.[59] The first step was to develop a ratio of California's nitric acid production capacity to the federal production capacity and then multiplying this ratio times the national estimates of CO_2-equivalent nitrous oxide emissions from nitric acid production.

California's nitric acid production capacity data were available for 1990, 1992, 1993, 1995, 1996, and 1998. Values for intervening years were estimated by interpolation, and values after 1998 were held constant at 1998 capacity. California's percentage of the national production capacity decreased steadily from 3.0 percent in 1990, to 1.4 percent in 1998. Thus, holding this percentage constant for 1999 through 2002 may slightly overstate California's nitrous oxide emissions from nitric acid production.

Line 31—Waste Combustion
Carbon dioxide and nitrous oxide emissions to the atmosphere occur when MSW is combusted to make electricity. See Line 14 (above) for a brief description of waste combustion and resulting carbon dioxide emissions. Nitrous oxide emissions are estimated in the same manner, but using an emission factor of 0.0001 ton of nitrous oxide emitted per ton of municipal solid waste combusted.

Line 32—Agricultural Soil Management
Nitrous oxide emissions from agricultural soils are affected by fertilizer use, amounts and types of residues incorporated into the soil, the type of soil, animal manures, and the amount of leaching and runoff. This method is the same as used in the 1990-1999 GHG emissions inventory with the following exception.

In the 1990-1999 inventory, the residue tonnages produced and incorporated into the soil were based on a residue-to-crop mass ratio. When these tonnages were compared to the total tonnages produced based on California factors (see Burning Ag Residues), they were up to five times greater than were calculated for agricultural burning. Therefore, the residue-to-crop mass ratio and the fraction of residue applied was adjusted down for barley, corn, rice, and wheat to reflect California factors for the amount of residue produced per acre and the fractions not burned. California specific factors for sorghum, oats, rye, soybeans, peanuts, and beans were not determined for this inventory.

Line 33—Manure Management

Nitrous oxide emissions from manure (and urine) occur from a nitrification process when ammonia in the waste first decomposes to nitrites in the presence of oxygen (aerobic conditions), followed by further decomposition to nitrous oxide under anaerobic conditions. Dry lot systems are generally aerobic. However, these may evolve to anaerobic conditions after rainfall.

A portion of the nitrous oxide generated from these wastes is included under Agricultural Soil Management (Line 32), including manure and urine in pastures and rangeland, and in paddocks, as well as manure used as a soil amendment. The remaining sources of nitrous oxide from manure management are estimated in this category of emissions.

Nitrous oxide emissions from this sector depend heavily on amount of un-volatilized organic nitrogen and ammonia in manure. This is called “total Kjeldahl nitrogen” and is estimated by multiplying animal population times TAM and the ratio of TAM to Kjeldahl nitrogen, times 0.80 (80 percent is assumed to not volatialize) and remain behind to decompose. All values are specific to type of animal and the feeding regimen. TAM and Kjeldahl nitrogen values are based on national animal characteristics and will be updated to reflect California-specific values in future updates to the inventory.

Line 34—Burning Agricultural Residues

Crop-specific nitrous oxide emissions are calculated in the same manner as methane emissions from burning agricultural residues (Line 25), except nitrous oxide emissions factors are substituted for methane emissions factors.

Line 35—Wastewater (formerly, Human Sewage)

Nitrous oxide emissions occur as a natural by-product of organic-laden domestic (human sewage) and industrial waste water, converting nitrate to nitrous oxide under anaerobic conditions.

Municipal wastewater emits nitrous oxide as a consequence of nitrogen in protein digested in the human diet. These emissions are estimated in the following steps:

- Obtain U.S. per capita protein consumption from the EPA Emissions Inventory Improvement Program guidance document[60] (this data shows the same value for 1998 to 2000, analysis assumes the value also applies through 2002).

- Multiply by the state population for each year,

- Multiply by 0.01 kilogram N_2O-N per kilogram N,

- Multiply by 44/28 (ratio of molecular weight of nitrous oxide to atomic weight of nitrogen),

- Multiply by global warming potential of nitrous oxide to obtain metric tons of carbon dioxide equivalent,

- Divide by 1,000,000 to get million metric tons CO_2-equivalent.

This is the same approach used in the 1990-1999 GHG emissions inventory.

Industrial wastewater emissions occur from processing fruits and vegetables, red meat and poultry, and pulp and paper. These are not yet included in the California inventory, but should be added.

<u>Line 36—Mobile Source Combustion</u>
Combustion of gasoline and diesel in internal combustion engines releases small quantities of nitrous oxide in the exhaust. The rate of emissions depends on engine type and type of pollution control applied to the engine.

CARB staff provided annual nitrous oxide emissions from gasoline and diesel fueled vehicles from their EMFAC model. These were adjusted to tons per year by multiplying by 365, then from short tons to metric tons by multiplying by 0.9072, and by the nitrous oxide global warming potential to convert to CO_2-equivalents.

<u>Line 37—Stationary Source Combustion</u>
Nitrous oxide data were not available from the CARB. Instead, emissions were calculated using fuel consumption data from the EIA's *State Energy Data Report* for 1990 to 2001. Because data were no more current than 2001 and magnitude of emissions is small, values for 2002 were assumed to equal 2001 values. Values were derived for electricity generation, industrial, commercial/institutional, and residential fuel uses. The process is the same as Line 28, Stationary Source Combustion (methane) for electricity production, except the emission factor in Step 4 is replaced with the appropriate value for nitrous oxide, in units of grams nitrous oxide per gigajoule of fuel use: coal = 1.4, petroleum = 0.6, natural gas = 0.1, and wood = 4.0

High Global Warming Potential Gas Emissions

High global warming potential gas emissions include use of substitution of other gases for ozone-depleting gases, semiconductor manufacturing, and electricity transmission and distribution. Substitution of ozone-depleting gases involves a number of hydrofluorocarbons (HFCs).

High global warming potential gas emissions are converted into carbon dioxide equivalent emissions by multiplying the methane emissions in millions of metric tons by their 100-year GWP. For this inventory, we choose a GWP from the Second Assessment Report. The GWP for high global warming potential gases is different for each gas. The values used in this inventory are shown in Table 1 of the 1990-1999 California GHG inventory.[61]

Line 38—High Global Warming Potential Gas Total Emissions
This line is simply the sum of Lines 39 to 41.

Line 39—Substitution of Ozone-Depleting Substances
Several anthropogenic substances have been linked to ozone depletion over the Earth's Polar Regions and are being phased out due to international agreements. These ozone-depleting substances (ODS) were historically used in industrial refrigeration and space conditioning equipment, solvents, foams, etc. A wide range of replacement substances are being used in increasing amounts in the United States, and these are associated with global warming.

California ODS GHG emissions were estimated by scaling United States ODS emissions by the ratio of California-to-United States population, about 12 percent. This is the same method used in the 1990-1999 GHG inventory.[62]

Line 40—Semiconductor Manufacture
Semiconductor manufacturing releases several compounds that have strong global warming impacts, including trifluoromethane, perfluoromehtane, perfluoroethane, and SF_6. The exact combination of compounds is difficult to estimate.

California GHG emissions from semiconductor manufacturing operations were estimated by scaling U.S. ODS emissions by the ratio of California-to-United States population, about 12 percent. This is the same method as the 1990-1999 GHG emissions inventory.[63]

Line 41—Electricity Transmission & Distribution (Sulfur Hexafluoride)
Electricity transmission and distribution requires the use of circuit breakers, gas-insulated substations, and switch gear. Sulfur hexafluoride (SF_6) is used to insulate this equipment and can leak out, especially in older equipment. Emissions also occur during installation and servicing.

The Second Assessment Report global warming potential for SF_6 is 23,900 times that of carbon dioxide, so a small amount of SF_6 can significantly impact global warming. Fortunately, California utilities are finding that they can reduce maintenance costs by better management of SF_6. However, since California-specific data are not currently available, SF_6 emissions are estimated from national values, prorated by ratio of California to national energy consumption, expressed in GWh. This method is the same method as the 1990-1999 GHG inventory.[64] This approach probably overstates California's sulfur hexafluoride emissions because California utilities are implementing procedures to control their SF_6 emissions and reduce their maintenance costs.[65]

Table A-1. Fossil Fuel Emissions Factors and Percentage Oxidized (Fuels Where Values Do Not Vary from Year to Year)

Fuel	Percent Oxidized	Emission Factor (lb C/mm BTU)
Natural Gas	99.5	31.9
Petroleum Products		
- Asphalt	99	45.5
- Aviation Gasoline	99	41.6
- Distillate	99	44.0
- Jet Fuel	99	43.5
- Kerosene	99	43.5
- Liquefied Petroleum Gas	99.5	37.8
- Motor Gasoline	99	42.8
- Misc. Petroleum Products	99	44.7
- Petroleum Coke	99	61.4
- Refinery Still Gas	99	38.6

Table A-2. Fossil Fuel Emissions Factors and Percentage Oxidized (Fuels Where Values Vary from Year to Year)

	Percent Oxidized	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Coal														
- Commercial	99	55.66	55.69	55.66	55.66	55.66	55.66	55.66	55.66	55.67	55.66	55.66	55.66	55.66
- Industrial	99	55.80	55.80	55.69	55.66	55.66	55.66	55.66	55.71	55.79	55.80	55.80	55.80	55.80
- Utility	99	56.62	56.65	56.65	56.67	56.70	56.75	56.75	56.78	56.78	56.78	56.78	56.78	56.78

(Assume 2000 to 2002 values are constant at 1999 values)

Table A-3. Minerals Production in California
(Thousand Metric Tons)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cement													
- Portland	8,874	8,178	7,289	8,510	9,640	9,360	9,910	10,300	10,000	10,300	10,900	10,100	11,200
- Masonry					99	154	198	169	410	466	484	564	637
Total Cement	8,874	8,178	7,289	8,510	9,739	9,514	10,108	10,469	10,410	10,766	11,384	10,664	11,837
Lime Production	313.2	278.7	254.2	193.0	203.2	228.2	207.9	199.7	185.2	181.6	185.7	182.2	178.6
								(Shaded areas extrapolated from 1993-98)					
Limestone & Dolomite		17.8		18.2	23.5	23.4	25.3	23.2	25.0	26.9	28.3	27.9	35.7
	(1990 assumed equal to 1991; 1992 assumed equal to 1993)												
Soda Ash Consumption	522	502	506	502	501	520	511	518	514	514	511	510	514

Table A-4 Full Detail-California Greenhouse Gas Emissions ($MMTCO_2E$)

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Carbon Dioxide	**322.84**	**316.23**	**322.10**	**315.37**	**332.95**	**317.67**	**321.12**	**331.92**	**347.16**	**356.62**	**370.36**	**371.28**	**360.21**
Residential	**28.98**	**29.52**	**27.83**	**28.43**	**29.22**	**26.60**	**26.63**	**26.33**	**30.74**	**31.82**	**29.63**	**28.21**	**24.77**
Natural Gas	27.53	27.82	26.60	27.16	27.96	25.40	25.61	25.40	29.25	30.41	27.91	26.92	23.43
Petroleum	1.44	1.70	1.24	1.27	1.26	1.20	1.02	0.93	1.49	1.41	1.71	1.29	1.34
LPG	1.30	1.57	1.09	1.14	1.13	1.11	0.92	0.83	1.38	1.29	1.55	1.07	1.20
Kerosene	0.05	0.04	0.05	0.04	0.04	0.01	0.03	0.03	0.04	0.05	0.06	0.10	0.08
Distillate	0.09	0.08	0.10	0.10	0.10	0.08	0.06	0.07	0.07	0.08	0.11	0.13	0.06
Commercial	**13.79**	**13.37**	**11.06**	**10.98**	**11.60**	**11.09**	**11.03**	**11.19**	**16.33**	**21.45**	**17.53**	**11.50**	**15.50**
Coal	0.05	0.09	0.00	0.30	0.35	0.28	0.38	0.23	0.24	0.06	0.05	0.00	0.00
Natural Gas	10.54	10.09	9.29	9.33	9.92	9.11	9.27	9.64	14.53	19.82	15.80	9.94	14.23
Education	1.41	1.27	1.08	1.12	1.27	0.98	0.94	1.04	1.27	1.37	1.36	0.99	1.36
College	0.69	0.60	0.53	0.54	0.69	0.51	0.47	0.55	0.68	0.74	0.82	0.56	0.63
School	0.71	0.67	0.55	0.57	0.58	0.47	0.47	0.48	0.59	0.64	0.54	0.43	0.74
Food Services	1.88	1.87	1.84	1.87	1.89	1.89	1.94	2.02	2.16	2.26	2.27	2.18	2.26
Restaurant	1.63	1.63	1.61	1.62	1.64	1.63	1.68	1.74	1.85	1.93	1.95	1.87	1.96
Food & Liquor	0.25	0.25	0.24	0.25	0.26	0.25	0.26	0.28	0.31	0.33	0.33	0.32	0.30
Retail & Wholesale	0.60	0.55	0.54	0.61	0.65	0.59	0.49	0.55	0.56	0.62	0.58	0.51	0.58
Retail	0.29	0.26	0.22	0.23	0.23	0.19	0.19	0.19	0.23	0.25	0.22	0.20	0.26
Warehouse	0.31	0.29	0.31	0.24	0.26	0.37	0.27	0.32	0.30	0.33	0.32	0.28	0.31
Warehouse, refrigerated	0.00	0.00	0.00	0.15	0.15	0.03	0.03	0.03	0.04	0.04	0.04	0.02	0.02
Health Care	1.31	1.32	1.12	1.05	1.22	1.13	1.14	1.15	1.24	1.34	1.29	1.20	1.19
Hotel	0.67	0.65	0.62	0.60	0.62	0.60	0.60	0.61	0.64	0.67	0.66	0.63	0.62
Office	1.45	1.39	1.26	1.31	1.40	1.31	1.36	1.34	1.55	1.75	1.56	1.41	2.01
Transportation Services	0.03	0.04	0.03	0.04	0.04	0.03	0.04	0.03	0.05	0.06	0.05	0.04	0.00
Transportation	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01	0.00
Water- Transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Airports	0.02	0.03	0.02	0.03	0.03	0.02	0.04	0.02	0.04	0.05	0.04	0.03	0.00
Communication	0.07	0.07	0.06	0.04	0.06	0.06	0.06	0.08	0.06	0.07	0.06	0.05	0.11
U.S. Postal Service	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Telephone & Cell Phone	0.05	0.05	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.02

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Other Message Communication	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Radio Broadcasting Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Non-Specified (Communication)	0.00	0.00	0.00	0.00	0.02	0.01	0.02	0.03	0.01	0.01	0.01	0.01	0.06
Utilities	0.34	0.33	0.35	0.27	0.29	0.31	0.41	0.39	4.12	8.96	4.72	0.36	3.50
Electric, Natural Gas, Steam	0.14	0.16	0.16	0.10	0.11	0.12	0.17	0.14	3.83	8.65	4.41	0.13	3.26
Sewerage Systems	0.07	0.07	0.08	0.07	0.08	0.09	0.13	0.13	0.19	0.18	0.15	0.14	0.15
Water Supply	0.12	0.10	0.11	0.10	0.10	0.10	0.11	0.11	0.10	0.13	0.16	0.09	0.10
Street Lights	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
National Security	0.56	0.64	0.54	0.54	0.50	0.40	0.36	0.46	0.34	0.29	0.24	0.32	0.18
Non-specified (Services)	2.23	1.96	1.84	1.89	1.99	1.82	1.92	1.98	2.54	2.44	3.00	2.25	2.41
Petroleum	3.20	3.18	1.77	1.35	1.32	1.70	1.38	1.32	1.55	1.56	1.68	1.56	1.26
LPG	0.23	0.28	0.19	0.20	0.20	0.20	0.16	0.15	0.24	0.23	0.21	0.21	0.21
Motor Gasoline	0.71	0.61	0.55	0.10	0.08	0.09	0.08	0.08	0.09	0.08	0.09	0.09	0.09
Kerosene	0.07	0.04	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.02	0.03	0.01
Distillate	1.78	1.89	0.99	1.03	1.03	1.40	1.12	1.09	1.17	1.22	1.37	1.21	0.95
Residual Oil	0.41	0.37	0.02	0.01	0.00	0.00	0.01	0.00	0.04	0.00	0.00	0.02	0.00
Industrial	**68.16**	**66.45**	**62.91**	**65.36**	**66.82**	**64.00**	**70.14**	**74.54**	**77.23**	**72.12**	**76.81**	**79.51**	**74.62**
Natural Gas	29.47	29.07	25.67	26.07	26.42	29.61	33.25	36.59	40.45	36.33	37.28	35.64	34.38
Agriculture	0.54	0.50	0.48	0.41	0.62	0.53	0.59	0.66	0.73	0.85	0.93	0.66	0.66
Crop Production	0.44	0.42	0.41	0.34	0.45	0.40	0.49	0.57	0.63	0.70	0.74	0.56	0.58
Livestock Production	0.05	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.08	0.08	0.07	0.07
Irrigation	0.04	0.02	0.02	0.02	0.12	0.08	0.05	0.04	0.03	0.08	0.11	0.03	0.01
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mining	0.03	0.03	0.04	0.04	0.04	0.31	0.34	0.32	0.40	0.32	0.32	0.31	0.29
Metal	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.08	0.00	0.00	0.00	0.29
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Minerals	0.03	0.03	0.04	0.04	0.04	0.30	0.34	0.32	0.31	0.32	0.32	0.31	0.00
Manufacturing	13.98	13.19	11.94	11.79	12.33	12.42	12.81	12.51	14.19	13.36	13.46	12.38	12.93
Food	3.05	3.25	3.21	3.26	3.25	3.15	3.11	3.14	3.58	3.73	3.64	3.29	3.20
Food Processing	1.19	1.32	1.36	1.33	1.24	1.34	1.39	1.37	1.60	1.66	1.48	1.24	1.32
Sugar & Confections	0.46	0.47	0.37	0.41	0.47	0.42	0.27	0.23	0.30	0.36	0.39	0.35	0.00

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Non-specified (Food Processing)	1.40	1.46	1.48	1.53	1.53	1.38	1.44	1.54	1.67	1.72	1.77	1.71	1.88
Tobacco	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textiles	0.38	0.35	0.35	0.39	0.43	0.43	0.45	0.48	0.51	0.56	0.56	0.48	0.43
Textile Mills	0.32	0.30	0.31	0.34	0.38	0.39	0.40	0.43	0.46	0.52	0.52	0.44	0.40
Leather	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.04	0.04	0.04	0.04	0.03
Wood & Furniture	0.23	0.22	0.23	0.25	0.26	0.40	0.35	0.30	0.31	0.30	0.30	0.33	0.16
Lumber & Wood Products	0.18	0.18	0.19	0.22	0.22	0.36	0.31	0.27	0.26	0.26	0.25	0.29	0.12
Furniture & Fixtures	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.04	0.04
Pulp & Paper	1.79	1.52	1.04	1.15	1.54	1.57	1.84	1.48	1.78	1.39	1.58	1.49	0.94
Pulp Mills	0.06	0.08	0.13	0.05	0.03	0.00	0.00	0.00	0.20	0.00	0.20	0.00	0.22
Paper Mills	0.39	0.33	0.25	0.40	0.67	0.65	0.71	0.48	0.58	0.56	0.53	0.52	0.53
Paperboard Mills	0.90	0.73	0.35	0.40	0.54	0.65	0.82	0.72	0.69	0.53	0.57	0.65	0.00
Non-specified (Pulp & Paper)	0.44	0.38	0.32	0.30	0.30	0.27	0.31	0.28	0.32	0.30	0.29	0.32	0.20
Printing & Publishing	0.11	0.12	0.11	0.12	0.13	0.15	0.14	0.14	0.15	0.14	0.11	0.11	0.08
Chemicals & Allied Products	1.75	1.57	1.21	0.97	1.12	1.10	1.16	0.98	1.31	1.05	1.26	1.10	1.05
Plastics & Rubber	0.23	0.22	0.19	0.19	0.19	0.20	0.20	0.23	0.25	0.27	0.26	0.21	0.22
Plastics	0.18	0.17	0.15	0.15	0.15	0.16	0.16	0.18	0.21	0.22	0.22	0.17	0.00
Non-specified (Plastics & Rubber)	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.22
Stone, Clay, Glass, & Cement	3.47	3.16	3.04	2.89	2.78	2.88	2.97	3.07	3.43	3.05	2.97	2.84	2.87
Flat Glass	1.74	1.58	1.52	1.45	1.39	1.44	1.49	1.54	1.72	1.53	1.49	1.42	1.43
Glass containers	0.68	0.64	0.62	0.61	0.59	0.53	0.53	0.51	0.54	0.51	0.49	0.46	0.58
Cement	0.18	0.19	0.17	0.19	0.13	0.19	0.19	0.16	0.23	0.14	0.16	0.11	0.18
Non-specified (Stone, Clay, Glass, & Cement)	0.87	0.75	0.73	0.65	0.66	0.73	0.77	0.86	0.94	0.87	0.84	0.85	0.68
Primary Metals	0.94	0.89	0.75	0.76	0.85	0.78	0.82	0.84	0.87	0.88	0.89	0.78	0.68
Metal Durables	0.91	0.82	0.76	0.78	0.76	0.79	0.81	0.83	0.86	0.81	0.79	0.77	0.82
Fabricated Metal Products	0.58	0.58	0.55	0.55	0.53	0.56	0.58	0.59	0.61	0.59	0.59	0.59	0.54
Computers & Office Machines	0.13	0.12	0.10	0.10	0.09	0.08	0.08	0.08	0.09	0.09	0.09	0.08	0.18
Industrial Machinery & Equipment	0.20	0.12	0.12	0.13	0.14	0.15	0.16	0.16	0.17	0.13	0.12	0.11	0.10

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Electric & Electronic Equipment	0.35	0.33	0.31	0.30	0.29	0.28	0.29	0.31	0.33	0.37	0.33	0.27	0.21
Telephone & Broadcasting Equip.	0.06	0.04	0.04	0.03	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.00
Semiconductors & Related Products	0.19	0.20	0.19	0.18	0.18	0.18	0.20	0.21	0.22	0.23	0.21	0.17	0.17
Non-specified (Elec. Equipment)	0.10	0.09	0.09	0.09	0.08	0.08	0.07	0.08	0.09	0.11	0.08	0.07	0.04
Transportation Equipment	0.53	0.53	0.53	0.51	0.51	0.47	0.43	0.44	0.48	0.51	0.49	0.46	0.41
Instruments & Related Products	0.07	0.09	0.08	0.10	0.09	0.08	0.09	0.09	0.10	0.11	0.10	0.10	0.00
Construction	0.12	0.11	0.08	0.09	0.09	0.09	0.11	0.13	0.15	0.13	0.12	0.11	0.09
Non-specified (Industrial)	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.06	0.06	0.05	0.04	1.76
Energy Industrial Sector	14.78	15.28	13.13	13.79	13.41	16.31	19.43	23.03	25.05	21.70	22.50	22.18	20.41
Transformation at Refinery	0.00	0.00	0.00	1.30	1.88	1.25	2.63	2.00	2.56	1.84	1.91	2.07	0.73
Refining	4.38	4.11	3.73	3.68	3.15	4.27	5.61	5.86	5.48	5.00	5.57	4.87	6.14
Oil & Gas Extraction	10.40	11.16	9.40	8.81	8.38	10.78	11.19	15.17	17.01	14.86	15.02	15.23	13.54
Flaring	0.15	0.07	0.08	0.04	0.03	0.04	0.07	0.07	0.09	0.10	0.07	0.11	0.09
Natural Gas Liquids	0.10	0.06	0.08	0.08	0.08	0.07	0.04	0.04	0.04	0.04	0.21	0.19	0.03
Petroleum	35.23	34.15	34.41	37.65	38.57	31.85	34.06	34.38	32.77	31.44	34.96	39.44	35.91
LPG	1.63	1.47	2.36	1.65	1.80	1.34	1.01	0.84	0.66	0.78	0.76	0.97	0.76
Manufacturing	0.83	0.55	0.79	0.59	0.64	0.55	0.45	0.39	0.37	0.52	0.30	0.30	0.51
Chemicals & Allied Products	0.19	0.19	0.22	0.21	0.22	0.22	0.24	0.24	0.25	0.26	0.24	0.22	0.22
Non-specified (Industry)	0.64	0.36	0.58	0.39	0.42	0.33	0.21	0.14	0.12	0.26	0.06	0.08	0.29
Oil Refinery Use	0.80	0.92	1.57	1.05	1.16	0.79	0.56	0.46	0.29	0.25	0.47	0.66	0.25
Motor Gasoline	1.17	1.21	1.22	0.99	1.02	1.05	0.99	1.04	1.17	0.69	0.71	1.64	1.74
Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.47	0.51
Non-specified (Agriculture)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.36	0.39
Non-specified (Industrial)	1.17	1.21	1.22	0.99	1.02	1.05	0.99	1.04	1.17	0.69	0.14	0.81	0.85
Refinery Still Gas	15.69	15.63	15.11	18.72	18.95	13.26	15.33	15.16	14.93	13.66	13.12	14.80	14.70
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.05	0.07	0.07	0.03
Non-specified (Industrial)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.04	0.07	0.06	0.01
Non-specified (Agricultural)	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01
Distillate	7.35	6.01	5.45	5.63	6.09	5.12	5.12	6.07	5.61	6.51	8.16	9.18	6.28
Non-specified (Agriculture)	3.29	2.70	3.17	3.10	3.17	2.55	2.87	3.62	3.33	3.91	3.98	3.99	3.58

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Non-specified (Industry)	3.85	3.20	2.14	2.37	2.77	2.47	2.20	2.39	2.22	2.48	4.09	5.07	2.58
Oil and Gas Extraction	0.21	0.11	0.14	0.16	0.14	0.10	0.05	0.05	0.06	0.11	0.10	0.10	0.12
Oil Refinery Use (022)	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00
Residual Oil	0.82	0.81	0.81	0.75	0.74	0.77	0.21	0.10	0.08	0.33	0.05	0.23	0.09
Refining (022)	0.21	0.21	0.16	0.18	0.18	0.12	0.09	0.06	0.06	0.03	0.00	0.00	0.00
Oil & Gas Extraction (023)	0.01	0.03	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.22	0.07
Non-specified (Industry)	0.59	0.57	0.58	0.57	0.56	0.65	0.12	0.04	0.02	0.28	0.05	0.01	0.02
Petroleum Coke	6.76	7.48	7.76	8.20	8.42	8.87	10.09	9.83	8.71	7.59	10.56	10.97	10.56
Oil Refinery Use (022)	6.76	7.42	7.61	7.66	7.52	7.43	9.50	9.09	8.07	6.95	9.77	10.25	9.71
Cement Manufacturing	0.00	0.05	0.15	0.55	0.90	1.43	0.60	0.74	0.65	0.64	0.79	0.72	0.85
Lubricants	0.87	0.78	0.79	0.81	0.84	0.83	0.81	0.85	0.89	0.90	0.89	1.08	1.07
Waxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Asphalt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Special Naphtha	0.93	0.75	0.89	0.89	0.69	0.60	0.48	0.47	0.69	0.94	0.63	0.51	0.66
Other Petroleum Products	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	3.36	3.17	2.76	1.55	1.76	2.48	2.79	3.52	3.98	4.30	4.35	4.23	4.31
Transportation	161.08	156.70	161.88	158.85	163.86	166.16	167.38	170.84	173.34	176.26	181.67	181.56	189.88
Natural Gas	0.16	0.18	0.17	0.17	0.17	0.17	0.21	1.42	0.71	0.73	0.76	0.79	0.76
Rail	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Road	0.06	0.06	0.05	0.06	0.07	0.07	0.10	0.11	0.12	0.14	0.14	0.12	0.10
Freight	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.03
Passenger	0.02	0.02	0.02	0.02	0.03	0.03	0.05	0.05	0.05	0.06	0.06	0.05	0.04
Private Auto	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxi & Buses	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.00
Non-specified (Local Transit)	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.03	0.04
Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Air	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.01	0.04	0.01	0.06
Non-specified (Air Transport)	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.01	0.04	0.01	0.06
Pipeline	0.07	0.09	0.09	0.09	0.07	0.08	0.09	1.29	0.55	0.57	0.57	0.65	0.58
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.21	0.48	0.50	0.50	0.56	0.50
Other Than Natural Gas Pipeline	0.07	0.09	0.09	0.09	0.07	0.08	0.09	0.08	0.07	0.06	0.07	0.08	0.09

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Petroleum	160.92	156.52	161.71	158.69	163.69	165.99	167.17	169.42	172.62	175.53	180.91	180.77	189.13
LPG	0.21	0.17	0.15	0.15	0.23	0.13	0.11	0.08	0.15	0.09	0.36	0.43	0.19
Motor Gasoline	111.33	108.69	115.01	113.14	112.72	114.84	113.85	114.51	116.91	120.21	122.01	124.35	130.64
Aviation Gasoline	0.38	0.38	0.37	0.28	0.27	0.28	0.27	0.29	0.20	0.29	0.25	0.23	0.25
Jet Fuel	24.00	22.77	21.92	22.56	24.98	24.10	26.24	26.08	26.64	24.95	26.04	24.58	25.87
Domestic Aviation	24.00	22.77	21.92	22.56	24.98	24.10	26.24	26.08	26.64	24.95	26.04	24.58	25.87
Distillate	22.66	22.49	22.50	20.79	23.55	24.48	24.65	26.78	27.02	28.08	30.23	29.58	30.61
Railroad	2.24	2.37	2.16	1.90	2.06	2.35	2.51	2.48	2.61	2.70	2.97	2.80	2.94
Road Transportation	18.28	17.78	18.52	18.33	19.95	21.00	21.26	22.99	23.50	24.70	26.45	26.40	27.17
Water Transportation	0.30	0.69	0.41	0.14	0.44	0.02	0.06	1.09	0.68	0.57	0.71	0.00	0.00
Non-specified (Transport)	1.82	1.64	1.43	0.41	1.10	1.12	0.82	0.21	0.23	0.11	0.10	0.38	0.50
Residual Oil	1.19	0.97	0.70	0.68	0.82	1.07	0.98	0.56	0.51	0.72	0.84	0.79	0.77
Water Transportation	1.19	0.97	0.69	0.67	0.81	0.99	0.91	0.52	0.50	0.71	0.84	0.79	0.76
Non-specified (Transport)	0.00	0.00	0.01	0.01	0.01	0.08	0.07	0.03	0.02	0.01	0.00	0.00	0.01
Lubricants	1.16	1.04	1.06	1.08	1.13	1.11	1.08	1.14	1.19	1.20	1.19	0.81	0.81
Non Specified Fuel (Pipeline Transport)	0.09	0.12	0.12	0.12	0.10	0.11	0.12	0.11	0.10	0.09	0.09	0.12	0.00
Electricity Generation (In State)	38.74	39.02	46.65	41.68	49.33	37.73	33.61	36.48	39.32	43.33	51.97	56.28	43.47
Natural Gas	36.42	36.51	43.61	38.68	46.23	35.00	31.19	34.38	37.31	41.09	49.71	54.14	41.09
Commercial CHP	0.64	0.57	0.64	0.66	0.73	0.75	0.77	0.73	0.74	0.73	0.71	0.65	0.64
Electric CHP	6.46	6.70	7.36	7.65	7.87	7.85	7.80	8.23	8.16	8.15	7.98	7.30	9.60
Industrial CHP	4.19	4.52	4.38	4.41	4.55	4.58	5.05	4.75	4.78	4.76	4.73	4.80	5.22
Utility	24.89	24.37	30.78	25.34	32.66	21.40	17.23	20.33	14.57	7.68	6.85	6.35	4.73
Merchant Power	0.24	0.35	0.46	0.62	0.42	0.42	0.34	0.34	9.05	19.78	29.44	35.04	20.91
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	2.33	2.51	3.04	3.00	3.10	2.73	2.42	2.10	2.01	2.23	2.26	2.14	2.38
Electric CHP	1.41	1.99	2.11	2.21	2.10	2.00	1.71	1.57	1.72	1.91	1.93	1.80	2.03
Industrial CHP	0.75	0.30	0.70	0.56	0.78	0.73	0.71	0.54	0.29	0.32	0.32	0.34	0.34
Merchant Power	0.17	0.22	0.23	0.23	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Not Sector-Specific; Other End Use	1.09	0.57	0.48	0.56	0.65	0.53	0.47	0.40	-0.12	0.60	0.86	0.70	0.68
Natural Gas	1.09	0.57	0.48	0.56	0.65	0.53	0.47	0.40	-0.12	0.60	0.76	0.54	0.55
Liquefied Petroleum Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.17	0.13

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Cement Production	4.62	4.26	3.80	4.43	5.07	4.96	5.27	5.45	5.42	5.61	5.93	5.56	6.17
Lime Production	0.25	0.22	0.20	0.15	0.16	0.18	0.16	0.16	0.15	0.14	0.15	0.14	0.14
Limestone & Dolomite Consumption	0.16	0.15	0.13	0.13	0.17	0.23	0.26	0.20	0.21	0.25	0.18	0.17	0.23
Soda Ash Consumption	0.22	0.21	0.21	0.21	0.21	0.22	0.21	0.22	0.21	0.21	0.21	0.21	0.21
Carbon Dioxide Consumption	0.08	0.08	0.07	0.08	0.08	0.08	0.07	0.07	0.08	0.07	0.08	0.07	0.11
Waste Combustion	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.13	0.12	0.13	0.13
Forests	4.51	4.50	4.49	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.47	4.47
Rangeland	0.65	0.65	0.65	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
Woody Ag Soils	0.27	0.27	1.15	(0.93)	(0.04)	(0.04)	(0.04)	(0.23)	(4.67)	(1.31)	(0.49)	0.94	0.15
Non-Woody Ag Soils	0.04	0.04	0.36	0.10	0.41	0.41	0.41	0.67	3.43	0.53	0.31	1.03	-1.20
Ag soil Liming	0.07	0.10	0.11	0.07	0.16	0.27	0.27	0.35	0.25	0.30	0.27	0.16	0.23
Methane Emissions	31.11	31.12	31.10	30.12	30.79	30.87	30.17	30.50	30.12	30.70	30.33	30.91	31.32
Petroleum & Natural Gas Supply System	1.27	1.22	1.16	1.10	1.05	0.99	0.97	0.96	0.94	0.92	0.91	0.90	0.90
Field Production	1.27	1.21	1.16	1.10	1.05	0.99	0.97	0.96	0.94	0.92	0.90	0.90	0.90
Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas Supply System	3.32	3.18	3.05	2.92	2.79	2.66	2.51	2.35	2.20	2.04	1.89	1.91	1.93
Processing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission & Storage	3.31	3.18	3.05	2.92	2.79	2.66	2.51	2.35	2.20	2.04	1.89	1.91	1.93
Landfills	10.00	9.96	9.92	9.89	9.85	9.81	9.83	9.85	9.88	9.90	9.92	9.99	10.07
Enteric Fermentation	8.25	7.94	8.07	7.22	7.82	7.95	7.41	7.53	7.49	7.75	7.34	7.67	7.73
Dairy Cattle	4.02	4.10	4.23	3.89	4.19	4.25	3.90	4.11	4.14	4.44	4.48	4.82	4.92
Beef Cattle	3.77	3.38	3.38	2.89	3.16	3.23	3.07	2.98	2.93	2.88	2.43	2.43	2.39
Horses	0.26	0.26	0.27	0.27	0.26	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Sheep	0.18	0.19	0.18	0.16	0.20	0.19	0.17	0.16	0.15	0.15	0.15	0.15	0.14
Swine	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01
Goats	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Manure Management	3.60	4.24	4.30	4.42	4.71	4.99	4.98	5.35	5.25	5.70	5.87	6.11	6.34
Beef Cattle	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.10	0.09	0.09	0.09
Dairy Cattle	3.20	3.82	3.88	4.00	4.29	4.57	4.58	4.94	4.85	5.29	5.47	5.73	5.95
Swine	0.07	0.08	0.10	0.10	0.09	0.09	0.08	0.08	0.07	0.07	0.06	0.04	0.06
Poultry	0.15	0.15	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.15	0.16	0.15

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Sheep	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.02
Goats	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Horses	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Flooded Rice Fields	0.41	0.36	0.41	0.45	0.50	0.48	0.52	0.54	0.47	0.52	0.57	0.49	0.55
Burning Ag Residues	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.10
Agricultural Crop Residues	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.03	0.03
Non-woody/Field	0.03	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.01	0.01
Barley	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Corn	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rice	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.01
Wheat	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Woody/Orchard & Vineyard	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02
Almonds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Walnuts	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Agricultural Waste Burning	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.06	0.07
Wastewater Treatment	1.59	1.62	1.65	1.67	1.68	1.69	1.70	1.73	1.75	1.78	1.81	1.85	1.88
Mobile Source Combustion	1.33	1.29	1.24	1.19	1.14	1.10	1.04	0.98	0.92	0.86	0.80	0.75	0.71
Gasoline Highway Vehicles	1.27	1.23	1.18	1.14	1.10	1.05	0.99	0.93	0.87	0.81	0.76	0.71	0.66
Passenger Cars	0.55	0.53	0.50	0.48	0.46	0.44	0.41	0.38	0.36	0.33	0.30	0.28	0.26
Light-Duty Trucks	0.33	0.31	0.30	0.29	0.28	0.26	0.25	0.23	0.21	0.20	0.18	0.17	0.16
Medium & Heavy-Duty Trucks	0.25	0.24	0.24	0.23	0.22	0.21	0.19	0.17	0.15	0.14	0.12	0.11	0.11
Motorcycles	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Other	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.14	0.15	0.14	0.13
Diesel Highway Vehicles	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Passenger Cars	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Light-Duty Trucks	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Medium & Heavy-Duty Trucks	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Aviation	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Stationary Source Combustion	1.25	1.22	1.19	1.17	1.14	1.11	1.11	1.12	1.12	1.13	1.14	1.14	1.11
Electricity Generation	0.02	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.00

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Industrial	0.46	0.45	0.44	0.43	0.42	0.41	0.42	0.42	0.42	0.43	0.43	0.43	0.43
Petroleum	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Natural Gas	0.35	0.34	0.33	0.33	0.32	0.31	0.31	0.32	0.32	0.32	0.32	0.32	0.32
Other	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07
Commercial	0.22	0.20	0.19	0.18	0.17	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Petroleum	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas	0.16	0.15	0.14	0.13	0.11	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11
Wood	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03
Residential	0.50	0.49	0.49	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Petroleum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Wood	0.47	0.46	0.46	0.46	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Other	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Nitrous Oxide Emissions	32.28	29.97	30.09	31.00	29.64	31.52	30.39	28.54	28.90	29.06	31.00	30.43	33.58
Nitric Acid Production	0.37	0.36	0.39	0.27	0.26	0.33	0.20	0.21	0.19	0.19	0.18	0.15	0.16
Waste Combustion	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Agricultural Soil Management	14.01	12.53	12.82	13.77	13.13	14.93	14.52	13.14	13.49	13.77	15.32	14.81	18.61
Direct	5.48	4.86	4.91	5.24	5.04	5.68	5.50	4.96	5.08	5.21	5.69	5.48	7.04
Fertilizers	2.69	2.17	2.35	2.79	2.43	3.18	3.01	2.42	2.57	2.60	3.17	2.92	4.39
Crop Residues	0.11	0.09	0.09	0.09	0.10	0.09	0.10	0.11	0.11	0.10	0.10	0.14	0.15
N-Fixing Crops	1.26	1.22	1.10	1.03	1.13	1.04	1.03	1.10	1.09	1.18	1.12	1.14	1.23
Histosols	0.17	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.12
Livestock	1.25	1.23	1.22	1.19	1.24	1.22	1.22	1.20	1.18	1.20	1.16	1.15	1.14
Indirect	5.84	5.31	5.45	5.81	5.57	6.27	6.14	5.64	5.78	5.88	6.57	6.41	7.75
Fertilizers	2.39	1.93	2.09	2.48	2.16	2.83	2.68	2.15	2.29	2.31	2.82	2.60	3.91
Livestock	3.45	3.38	3.36	3.33	3.41	3.45	3.46	3.49	3.49	3.57	3.75	3.81	3.85
Leaching/Runoff	2.70	2.36	2.46	2.72	2.52	2.98	2.89	2.54	2.63	2.67	3.06	2.93	3.82
Manure Management	0.81	0.76	0.74	0.72	0.70	0.72	0.70	0.70	0.70	0.71	0.90	0.92	0.92
Beef Cattle	0.17	0.14	0.13	0.15	0.12	0.14	0.11	0.12	0.13	0.13	0.14	0.14	0.14
Dairy Cattle	0.26	0.26	0.28	0.28	0.30	0.30	0.31	0.31	0.32	0.34	0.36	0.37	0.38
Swine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Poultry	0.37	0.35	0.32	0.28	0.27	0.27	0.27	0.25	0.24	0.22	0.38	0.39	0.38
Sheep	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Goats	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Horses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Burning Ag Residues	0.10	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.11	0.12	0.13	0.06	0.06
Non-woody/Field	0.07	0.06	0.07	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.09	0.03	0.03
Barley	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Corn	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rice	0.06	0.05	0.06	0.07	0.07	0.07	0.08	0.08	0.07	0.08	0.08	0.02	0.02
Wheat	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Woody/Orchard & Vineyard	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Almonds	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Walnuts	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wastewater	0.87	0.82	0.80	0.88	0.80	0.81	0.84	0.94	0.96	1.00	0.72	0.98	0.94
Municipal (formerly Human Sewage)	0.87	0.82	0.80	0.88	0.80	0.81	0.84	0.94	0.96	1.00	0.72	0.98	0.94
Industrial (Category not yet included in inventory)													
Mobile Source Combustion	15.70	15.02	14.85	14.90	14.27	14.26	13.65	13.11	13.14	12.95	13.43	13.17	12.55
Gasoline Highway Vehicles	7.85	7.58	7.43	7.33	7.17	6.94	6.00	5.75	5.60	5.38	5.16	4.78	4.35
Diesel Highway Vehicles	7.50	7.11	7.10	7.23	6.73	6.96	7.27	6.98	7.14	7.19	7.88	8.02	8.21
Aviation	0.35	0.34	0.32	0.33	0.37	0.36	0.39	0.39	0.39	0.37	0.39	0.36	0.00
Stationary Source Combustion	0.39	0.37	0.38	0.34	0.34	0.33	0.32	0.30	0.29	0.30	0.31	0.32	0.32
Electricity Generation	0.04	0.03	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Petroleum	0.01	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Natural Gas	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Wood	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	0.24	0.22	0.22	0.19	0.20	0.19	0.18	0.19	0.18	0.19	0.19	0.21	0.21
Coal	0.03	0.03	0.03	0.02	0.02	0.03	0.02	0.03	0.02	0.02	0.02	0.02	0.02
Petroleum	0.11	0.10	0.10	0.09	0.10	0.09	0.09	0.09	0.09	0.10	0.10	0.11	0.11

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Natural Gas	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02
Wood	0.08	0.07	0.07	0.05	0.05	0.05	0.04	0.05	0.04	0.05	0.05	0.06	0.06
Commercial/Institutional	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wood	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Residential	0.09	0.10	0.10	0.09	0.09	0.09	0.09	0.06	0.06	0.06	0.06	0.06	0.06
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.02	0.02	0.01	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.01	0.02	0.02
Wood	0.07	0.08	0.08	0.07	0.07	0.08	0.08	0.04	0.04	0.04	0.04	0.04	0.04
High Global-Warming Potential Gas Emissions	9.88	9.99	10.25	10.45	10.79	11.04	13.18	14.32	16.65	16.66	17.04	16.09	17.26
Substitution of Ozone-Depleting Substances	6.86	7.16	7.51	7.82	8.11	8.37	10.34	11.57	14.07	14.13	14.91	14.30	15.52
HFC-23	4.43	4.23	4.06	3.86	3.65	3.43	3.95	3.81	5.12	3.91	3.72	2.49	2.50
HFC-32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HFC-125	0.00	0.11	0.22	0.33	0.43	0.54	0.77	1.05	1.31	1.49	1.64	1.80	1.97
HFC-134a	0.00	0.44	0.89	1.33	1.77	2.21	2.99	3.84	4.51	5.21	5.78	6.38	6.91
HFC-143a	0.00	0.02	0.04	0.07	0.09	0.11	0.28	0.49	0.72	0.93	1.12	1.38	1.68
HFC-236fa	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.07	0.16	0.24	0.31	0.39
CF4	1.80	1.70	1.60	1.49	1.38	1.26	1.34	1.22	1.07	1.07	1.04	0.52	0.62
C2F6	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Others	0.04	0.08	0.12	0.16	0.19	0.23	0.42	0.55	0.68	0.77	0.78	0.81	0.86
Semiconductor Manufacture	0.36	0.36	0.36	0.46	0.52	0.67	0.67	0.77	0.87	0.89	0.76	0.55	0.53
Electricity Transmission & Distribution (SF6)	2.67	2.47	2.39	2.17	2.17	2.00	2.17	1.98	1.71	1.64	1.36	1.24	1.20
GROSS TOTALS:	396.11	387.31	393.54	386.94	404.17	391.10	394.86	405.28	422.83	433.04	448.74	448.70	442.37
GROSS TOTALS WITH ELECTRICITY IMPORTS:	439.43	430.38	436.56	427.76	447.35	429.61	435.43	452.25	475.69	484.72	489.21	496.07	494.10
Electricity Imports	43.31	43.07	43.02	40.82	43.18	38.51	40.57	46.97	52.86	51.68	40.48	47.37	51.73

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Forest Sinks	(13.14)	(13.11)	(13.09)	(13.07)	(13.05)	(13.05)	(13.05)	(13.05)	(13.05)	(13.05)	(13.05)	(13.04)	(13.03)
Rangeland Sinks	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.10)	(1.09)	(1.09)
Landfill Lumber Disposal Sinks	(3.73)	(3.54)	(3.35)	(3.17)	(2.98)	(2.79)	(2.61)	(2.42)	(2.23)	(2.05)	(2.74)	(3.31)	(3.88)
Yard Trimming Landfill Disposal Sinks	(4.74)	(4.54)	(4.34)	(4.14)	(3.94)	(3.74)	(3.54)	(3.34)	(3.14)	(2.94)	(2.72)	(2.51)	(2.30)
NET TOTALS:	373.40	365.01	371.66	365.46	383.10	370.43	374.57	385.37	403.31	413.90	429.13	428.75	422.08
NET TOTALS WITH ELECTRICITY IMPORTS:	416.72	408.08	414.68	406.28	426.29	408.93	415.14	432.34	456.17	465.58	469.61	476.12	473.80
International "Bunker" Fuels	39.88	34.61	28.00	27.95	32.40	35.76	35.35	27.03	26.85	30.30	33.82	31.80	31.83
Jet Fuel (Aviation)	14.72	13.96	13.44	13.84	15.32	14.78	16.09	15.99	16.34	15.30	15.97	15.07	15.86
Distillate Oil (Marine)	1.23	1.01	0.71	0.69	0.84	1.03	0.95	0.54	0.52	0.74	0.88	0.80	0.69
Residual Oil (Marine)	23.93	19.63	13.85	13.42	16.25	19.95	18.31	10.50	9.99	14.27	16.98	15.93	15.27

APPENDIX B

FUEL USED IN CALIFORNIA
(TRILLION BTUS)

Source: California Energy Balance[66]

Notes:

Values are shown for 1990 to 2003 when available. Year 2003 values are shown for information purposes but are not shown in the main report because values were not available for all end use sectors and sub-sectors.

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Statewide Energy Use (Trillion BTUs)	**5,285.07**	**5,465.18**	**5,496.30**	**5,413.90**	**5,702.69**	**5,440.11**	**5,558.42**	**5,800.83**	**6,175.57**	**6,302.03**	**6,508.65**	**6,459.91**	**6,209.86**
Residential (125)	**544.32**	**553.93**	**523.24**	**534.55**	**549.45**	**500.17**	**501.20**	**495.79**	**577.66**	**598.33**	**555.80**	**530.12**	**465.00**
Natural Gas (125)	**521.53**	**527.03**	**503.80**	**514.49**	**529.55**	**481.20**	**485.15**	**481.08**	**554.12**	**575.99**	**528.74**	**509.90**	**443.88**
Petroleum	**22.80**	**26.90**	**19.44**	**20.06**	**19.89**	**18.97**	**16.05**	**14.71**	**23.54**	**22.34**	**27.06**	**20.22**	**21.12**
LPG (125)	20.84	25.12	17.40	18.16	18.00	17.69	14.74	13.33	22.02	20.65	24.80	17.11	19.16
Kerosene (125)	0.74	0.61	0.67	0.52	0.49	0.20	0.43	0.42	0.49	0.64	0.78	1.38	1.08
Distillate (125)	1.21	1.17	1.37	1.39	1.40	1.07	0.89	0.96	1.03	1.05	1.47	1.73	0.88
Commercial	**244.76**	**236.59**	**201.03**	**199.14**	**210.49**	**199.49**	**199.21**	**203.76**	**299.90**	**398.29**	**323.51**	**210.23**	**287.54**
Coal (124)	**0.56**	**1.00**	**0.00**	**3.29**	**3.86**	**3.10**	**4.12**	**2.51**	**2.64**	**0.64**	**0.57**	**0.00**	**0.00**
Natural Gas	**199.58**	**191.16**	**176.01**	**176.79**	**187.92**	**172.51**	**175.69**	**182.62**	**275.29**	**375.53**	**299.23**	**188.28**	**269.64**
Education (095)	26.64	24.10	20.49	21.19	24.03	18.57	17.81	19.65	24.03	26.00	25.79	18.74	25.82
College	13.13	11.38	10.01	10.30	13.07	9.73	8.95	10.51	12.94	13.93	15.62	10.59	11.85
School	13.51	12.72	10.48	10.89	10.95	8.83	8.86	9.14	11.09	12.07	10.17	8.14	13.97
Food Services (098)	35.59	35.48	34.94	35.37	35.88	35.71	36.83	38.25	40.84	42.72	43.09	41.36	42.81
Restaurant	30.78	30.82	30.48	30.72	30.98	30.95	31.86	32.98	35.04	36.54	36.90	35.35	37.13
Food & Liquor	4.81	4.66	4.45	4.66	4.90	4.76	4.97	5.27	5.80	6.18	6.18	6.01	5.68
Retail & Wholesale (101)	11.35	10.44	10.19	11.58	12.28	11.19	9.27	10.35	10.67	11.73	11.03	9.73	11.07
Retail	5.45	4.91	4.22	4.28	4.45	3.67	3.64	3.66	4.29	4.77	4.15	3.87	4.87
Warehouse	5.89	5.53	5.96	4.48	4.99	6.94	5.05	6.11	5.69	6.21	6.15	5.40	5.83
Warehouse, refrigerated	0.00	0.00	0.00	2.81	2.84	0.58	0.58	0.58	0.69	0.76	0.73	0.45	0.37
Health Care (105)	24.88	25.02	21.23	19.88	23.07	21.42	21.63	21.83	23.52	25.45	24.37	22.68	22.63
Hotel (106)	12.61	12.31	11.74	11.34	11.67	11.31	11.33	11.63	12.14	12.70	12.48	11.96	11.83
Office (107)	27.38	26.30	23.94	24.81	26.45	24.75	25.85	25.48	29.31	33.13	29.62	26.65	38.16
Transportation Services (108)	0.65	0.71	0.51	0.74	0.71	0.59	0.82	0.54	1.02	1.20	1.02	0.81	0.00
Transportation	0.13	0.15	0.15	0.15	0.14	0.11	0.08	0.09	0.11	0.13	0.14	0.22	0.00
Water Transportation	0.07	0.08	0.07	0.05	0.07	0.07	0.07	0.06	0.07	0.08	0.10	0.07	0.00

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Airports	0.44	0.48	0.29	0.54	0.50	0.41	0.68	0.39	0.84	0.99	0.79	0.52	0.00
Communication (112)	1.31	1.38	1.10	0.82	1.16	1.04	1.17	1.46	1.13	1.23	1.08	0.89	2.02
U.S. Postal Service	0.27	0.28	0.23	0.26	0.34	0.35	0.42	0.33	0.39	0.40	0.35	0.31	0.31
Telephone & Cell Phone Service	0.90	0.95	0.74	0.39	0.42	0.36	0.36	0.39	0.43	0.49	0.39	0.34	0.43
Other Message Communication	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11
Radio Broadcasting Stations	0.09	0.09	0.08	0.08	0.09	0.08	0.09	0.12	0.11	0.12	0.10	0.12	0.12
Non-Specified (Communication)	0.04	0.05	0.05	0.08	0.31	0.25	0.30	0.62	0.21	0.24	0.25	0.11	1.04
Utilities (118)	6.35	6.33	6.68	5.13	5.41	5.89	7.81	7.32	77.99	169.67	89.43	6.80	66.35
Electric, Steam Natural Gas,	2.66	2.97	3.09	1.96	2.11	2.25	3.26	2.74	72.52	163.83	83.60	2.46	61.67
Sewerage Systems	1.39	1.38	1.57	1.28	1.43	1.75	2.48	2.50	3.58	3.34	2.90	2.61	2.83
Water Supply	2.30	1.98	2.02	1.89	1.86	1.89	2.06	2.08	1.89	2.50	2.94	1.73	1.84
Street Lights	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
National Security (123)	10.61	12.04	10.27	10.17	9.55	7.53	6.86	8.67	6.49	5.40	4.50	5.97	3.35
Non Specified (Services)	42.20	37.05	34.92	35.76	37.71	34.51	36.32	37.44	48.15	46.28	56.83	42.70	45.59
Petroleum	**44.61**	**44.43**	**25.02**	**19.05**	**18.71**	**23.88**	**19.40**	**18.63**	**21.96**	**22.12**	**23.71**	**21.95**	**17.90**
LPG (124)	3.68	4.43	3.07	3.21	3.18	3.12	2.60	2.35	3.89	3.64	3.32	3.32	3.32
Motor Gasoline (124)	10.12	8.65	7.80	1.37	1.19	1.24	1.18	1.18	1.27	1.20	1.22	1.26	1.30
Kerosene (094)	0.95	0.50	0.23	0.11	0.13	0.11	0.11	0.07	0.15	0.39	0.23	0.36	0.16
Distillate (124)	24.61	26.05	13.67	14.27	14.17	19.38	15.43	15.01	16.19	16.89	18.93	16.77	13.12
Residual Oil (124)	5.25	4.80	0.25	0.10	0.04	0.02	0.08	0.01	0.47	0.00	0.00	0.24	0.00
Industrial	**1,100.22**	**1,358.31**	**1,257.87**	**1,308.04**	**1,327.56**	**1,340.79**	**1,495.89**	**1,636.45**	**1,730.79**	**1,586.76**	**1,656.38**	**1,682.75**	**1,608.55**
Natural Gas	**528.32**	**814.15**	**710.57**	**731.40**	**731.92**	**846.47**	**975.52**	**1,106.28**	**1,214.94**	**1,077.68**	**1,110.54**	**1074.33**	**1048.77**
Agriculture	10.15	9.46	9.13	7.85	11.72	9.95	11.25	12.56	13.76	16.16	17.66	12.48	12.54
Crop Production (027)	8.42	8.02	7.83	6.49	8.52	7.62	9.36	10.86	11.98	13.18	13.95	10.54	10.95
Livestock Production (028)	1.00	1.06	1.00	0.95	0.94	0.89	0.91	1.01	1.12	1.47	1.58	1.39	1.32

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Irrigation (029)	0.72	0.37	0.30	0.41	2.26	1.44	0.98	0.70	0.66	1.51	2.13	0.55	0.26
Other (030)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Mining	0.52	0.58	0.77	0.68	0.71	5.83	6.49	6.14	7.50	6.07	6.13	5.82	5.55
Metal (032)	0.01	0.01	0.01	0.01	0.02	0.13	0.06	0.06	1.58	0.01	0.01	0.01	5.55
Coal (033)	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.01	0.01	0.02	0.02	0.00
Minerals (034)	0.52	0.57	0.76	0.67	0.69	5.68	6.43	6.07	5.92	6.05	6.10	5.80	0.00
Manufacturing	234.14	512.89	449.85	460.25	464.25	520.29	587.70	649.30	716.42	641.33	658.09	633.08	607.88
Food (036)	57.85	61.49	60.83	61.84	61.47	59.66	58.89	59.43	67.80	70.67	68.90	62.38	60.52
Food Processing	22.56	24.94	25.77	25.17	23.52	25.47	26.37	25.93	30.39	31.36	27.95	23.39	24.98
Sugar & Confections	8.73	8.93	6.96	7.74	8.93	8.01	5.20	4.33	5.74	6.73	7.47	6.63	0.00
Non-specified (Food Processing)	26.56	27.61	28.10	28.93	29.03	26.18	27.32	29.18	31.66	32.58	33.48	32.36	35.55
Tobacco (040)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textiles (041)	7.13	6.57	6.67	7.36	8.07	8.16	8.49	9.03	9.64	10.59	10.56	9.06	8.18
Textile Mills	6.16	5.63	5.82	6.44	7.16	7.34	7.59	8.07	8.76	9.76	9.77	8.30	7.58
Leather	0.15	0.12	0.07	0.10	0.11	0.09	0.09	0.07	0.07	0.07	0.07	0.09	0.00
Apparel	0.82	0.82	0.79	0.82	0.80	0.74	0.82	0.90	0.81	0.76	0.73	0.67	0.60
Wood & Furniture (045)	4.45	4.12	4.38	4.80	4.93	7.49	6.61	5.77	5.84	5.72	5.59	6.35	3.03
Lumber & Wood Products	3.47	3.34	3.67	4.09	4.22	6.83	5.93	5.03	5.02	4.85	4.73	5.59	2.26
Furniture & Fixtures	0.97	0.78	0.70	0.71	0.71	0.66	0.68	0.75	0.82	0.88	0.86	0.76	0.77
Pulp & Paper (048)	33.93	28.82	19.72	21.87	29.25	29.75	34.86	28.07	33.77	26.33	30.02	28.16	17.82
Pulp Mills	1.19	1.47	2.43	1.04	0.61	0.00	0.01	0.00	3.71	0.00	3.87	0.00	4.10
Paper Mills	7.36	6.18	4.65	7.56	12.69	12.30	13.41	9.15	10.93	10.55	9.99	9.80	10.01
Paperboard Mills	17.12	13.90	6.61	7.52	10.27	12.34	15.53	13.61	13.04	10.10	10.75	12.39	0.00
Non-specified (Pulp & Paper)	8.26	7.27	6.03	5.75	5.68	5.10	5.91	5.30	6.10	5.69	5.41	5.97	3.70
Printing & Publishing (053)	2.13	2.29	2.09	2.28	2.50	2.81	2.69	2.67	2.92	2.74	2.17	2.12	1.61

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Chemicals & Allied Products (054)	34.37	30.63	23.56	18.94	21.93	21.58	22.64	19.20	25.69	20.53	24.70	21.56	20.56
Plastics & Rubber (056)	4.42	4.24	3.76	3.69	3.81	3.88	3.90	4.42	4.95	5.23	5.16	4.05	4.24
Plastics	3.49	3.30	2.98	2.87	2.99	3.07	3.09	3.59	4.12	4.39	4.35	3.34	0.00
Non-specified (Plastics & Rubber)	0.93	0.94	0.78	0.82	0.83	0.80	0.81	0.83	0.83	0.85	0.82	0.71	4.24
Stone, Clay, Glass & Cement (059)	34.56	31.13	30.26	29.05	27.86	29.04	31.13	32.25	35.52	32.18	30.91	29.32	27.17
Flat Glass	1.68	1.17	1.47	1.65	1.55	1.74	2.99	3.17	3.02	3.29	2.75	2.38	0.00
Glass containers	12.97	12.19	11.72	11.59	11.26	10.04	9.99	9.70	10.21	9.67	9.22	8.77	11.03
Cement	3.48	3.51	3.20	3.55	2.48	3.53	3.60	3.07	4.44	2.66	2.98	2.10	3.35
Non-specified (Stone, Clay, Glass & Cement)	16.43	14.26	13.87	12.26	12.57	13.74	14.55	16.32	17.86	16.56	15.95	16.07	12.79
Primary Metals (064)	17.78	16.85	14.20	14.33	16.10	14.85	15.49	15.95	16.42	16.68	16.86	14.84	12.81
Metal Durables (065)	17.21	15.49	14.49	14.69	14.36	15.02	15.43	15.66	16.38	15.37	14.99	14.66	15.56
Fabricated Metal Products	10.94	11.03	10.41	10.47	10.11	10.62	10.89	11.17	11.47	11.20	11.14	11.23	10.27
Computers & Office Machines	2.46	2.19	1.90	1.84	1.63	1.59	1.50	1.50	1.68	1.76	1.62	1.43	3.34
Industrial Machinery & Equipment	3.81	2.27	2.18	2.38	2.61	2.81	3.04	3.00	3.22	2.41	2.23	2.00	1.95
Electric & Electronic Equipment (069)	6.57	6.30	5.97	5.59	5.48	5.35	5.51	5.91	6.33	6.97	6.27	5.16	4.03
Telephone & Broadcasting Equipment	1.21	0.75	0.72	0.55	0.45	0.40	0.43	0.47	0.54	0.61	0.63	0.64	0.00
Semiconductors & Related Products	3.54	3.84	3.59	3.38	3.49	3.43	3.72	3.91	4.15	4.29	4.05	3.13	3.28
Non-specified (Elec. Equipment)	1.82	1.71	1.65	1.66	1.54	1.52	1.36	1.53	1.63	2.06	1.58	1.39	0.75
Transportation Equipment (073)	10.05	10.01	9.95	9.66	9.71	8.96	8.18	8.42	9.11	9.65	9.26	8.62	7.78
Instruments & Related Products. (074)	1.34	1.62	1.55	1.80	1.74	1.56	1.64	1.71	1.91	2.12	1.81	1.82	0.00
Construction (075)	2.35	2.09	1.61	1.73	1.79	1.77	2.16	2.52	2.90	2.43	2.23	2.01	1.76
Non-specified (Industrial)	0.71	0.59	0.58	0.60	0.66	0.67	0.68	0.72	1.08	1.08	1.08	0.72	34.55
Energy Industrial Sector	279.98	289.36	248.77	261.23	253.99	308.89	368.10	436.26	474.50	411.05	426.25	420.07	386.57

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Transformation	0.00	0.00	0.00	24.63	35.67	23.69	49.79	37.95	48.49	34.94	36.14	39.22	13.88
Refining (022)	83.03	77.93	70.69	69.72	59.59	80.93	106.26	110.98	103.76	94.63	105.52	92.28	116.22
Oil & Gas Extraction (023)	196.95	211.43	178.08	166.89	158.73	204.27	212.05	287.33	322.25	281.47	284.58	288.57	256.47
Flaring (138)	2.82	1.28	1.47	0.78	0.59	0.84	1.29	1.29	1.67	1.99	1.34	2.16	1.68
Natural Gas Liquids (018)	**4.94**	**3.61**	**3.96**	**4.07**	**4.14**	**4.14**	**2.38**	**2.19**	**1.96**	**2.42**	**11.60**	**10.31**	**1.48**
Petroleum	**497.94**	**477.71**	**483.32**	**525.17**	**543.89**	**436.26**	**462.65**	**464.67**	**441.90**	**428.24**	**460.19**	**523.69**	**481.46**
LPG	53.82	45.44	64.26	46.62	52.88	42.95	33.00	27.89	24.58	32.26	23.43	27.04	31.60
Manufacturing (035)	41.03	30.70	39.21	29.75	34.40	30.24	23.99	20.54	19.98	28.20	15.95	16.41	27.53
Chemicals & Allied Products	9.21	10.54	10.67	10.29	11.93	12.20	12.65	12.82	13.38	13.94	12.70	11.86	11.85
Non-specified (Industry)	31.82	20.16	28.53	19.46	22.47	18.05	11.34	7.73	6.60	14.27	3.25	4.55	15.68
Oil Refinery Use (022)	12.79	14.75	25.06	16.86	18.48	12.71	9.02	7.35	4.60	4.06	7.48	10.63	4.06
Motor Gasoline (035)	16.60	17.17	17.31	13.99	14.48	14.96	14.05	14.79	16.58	9.77	10.12	23.28	24.73
Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.88	6.66	7.17
Non-specified (Agriculture)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.20	5.17	5.52
Non-specified (Industrial)	16.60	17.17	17.31	13.99	14.48	14.96	14.05	14.79	16.58	9.77	2.04	11.45	12.04
Refinery Still Gas (022)	246.92	245.98	237.75	294.61	298.08	208.59	241.13	238.49	234.96	214.91	206.46	232.79	231.34
Kerosene (035)	0.13	0.17	0.19	0.20	0.17	0.11	0.21	0.19	0.28	0.64	1.01	0.95	0.39
Non-specified (Industrial)	0.11	0.15	0.12	0.13	0.08	0.08	0.11	0.11	0.24	0.59	0.98	0.90	0.19
Non-specified (Agricultural)	0.03	0.02	0.07	0.07	0.09	0.03	0.09	0.08	0.04	0.05	0.03	0.06	0.20
Distillate	102.64	83.91	76.12	78.57	85.04	71.45	71.53	84.69	78.26	90.83	113.96	128.21	87.73
Non-specified (Agriculture)	45.90	37.64	44.21	43.33	44.30	35.55	40.12	50.52	46.49	54.59	55.55	55.74	49.98
Non-specified (Industry)	53.81	44.71	29.91	33.05	38.67	34.55	30.70	33.44	30.93	34.61	57.05	70.78	36.01
Oil and Gas Extraction	2.87	1.50	1.97	2.17	1.98	1.34	0.66	0.72	0.83	1.60	1.36	1.45	1.74
Oil Refinery Use (022)	0.05	0.06	0.02	0.02	0.09	0.00	0.04	0.02	0.01	0.03	0.01	0.24	0.01
Residual Oil	10.94	11.07	10.92	10.02	9.92	10.50	2.88	1.37	1.03	4.72	0.76	2.90	1.20

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Refining (022)	2.70	2.67	2.07	2.25	2.25	1.52	1.16	0.83	0.79	0.41	0.02	0.00	0.00
Oil & Gas Extraction (023)	0.17	0.33	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	2.76	0.87
Non-specified (Industry)	8.08	8.07	8.05	7.77	7.67	8.98	1.72	0.54	0.24	4.13	0.74	0.14	0.33
Petroleum Coke	66.88	73.96	76.77	81.16	83.33	87.71	99.85	97.25	86.19	75.10	104.45	108.52	104.48
Oil Refinery Use (022)	66.88	73.43	75.31	75.76	74.42	73.53	93.95	89.89	79.80	68.77	96.63	101.36	96.06
Cement Manufacturing	0.00	0.53	1.46	5.40	8.91	14.18	5.90	7.36	6.39	6.33	7.82	7.16	8.42
Lubricants (128)	**13.06**	**11.68**	**11.91**	**12.13**	**12.68**	**12.46**	**12.09**	**12.77**	**13.37**	**13.51**	**13.31**	**16.26**	**16.07**
Waxes	**3.25**	**4.02**	**4.26**	**4.58**	**4.64**	**4.64**	**5.39**	**4.84**	**4.69**	**4.15**	**3.66**	**4.02**	**3.56**
Asphalt	**98.62**	**94.57**	**89.97**	**82.51**	**81.20**	**81.04**	**82.28**	**76.39**	**103.34**	**129.31**	**125.30**	**127.05**	**129.32**
Special Naphtha	**12.88**	**10.37**	**12.32**	**12.32**	**9.55**	**8.35**	**6.67**	**6.47**	**9.60**	**13.02**	**8.72**	**7.03**	**9.17**
Other Petroleum Products (128)	**3.29**	**2.27**	**1.49**	**1.41**	**1.58**	**1.45**	**0.73**	**0.80**	**0.97**	**0.92**	**0.98**	**1.02**	**1.10**
Coal (035)	**36.6**	**34.5**	**30.0**	**17.0**	**19.2**	**27.0**	**30.5**	**38.4**	**43.3**	**46.8**	**47.4**	**46.1**	**46.9**
Transportation	**2,579.09**	**2,504.21**	**2,565.63**	**2,518.85**	**2,608.82**	**2,633.61**	**2,669.34**	**2,715.15**	**2,778.72**	**2,831.29**	**2,912.81**	**2,902.02**	**3,032.38**
Natural Gas	**3.05**	**5.08**	**4.92**	**4.77**	**4.51**	**4.65**	**5.56**	**28.33**	**14.89**	**15.12**	**15.63**	**16.56**	**16.02**
Rail (078)	0.36	0.35	0.25	0.18	0.18	0.17	0.18	0.14	0.25	0.25	0.23	0.28	0.18
Road (079)	1.06	1.12	1.01	1.11	1.35	1.34	1.95	2.10	2.29	2.68	2.65	2.23	1.85
Freight	0.30	0.27	0.25	0.26	0.26	0.22	0.23	0.22	0.25	0.28	0.22	0.22	0.52
Passenger	0.38	0.42	0.38	0.43	0.55	0.56	0.86	0.94	1.02	1.20	1.22	1.00	0.67
Private Auto	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxi & Buses	0.19	0.22	0.16	0.18	0.26	0.27	0.45	0.40	0.46	0.49	0.48	0.52	0.00
Non-specified (Local Transit)	0.20	0.21	0.23	0.25	0.28	0.29	0.41	0.54	0.56	0.71	0.74	0.48	0.67
Water (085)	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.02	0.05
Air (086)	0.35	0.36	0.27	0.24	0.25	0.18	0.18	0.18	0.56	0.24	0.78	0.18	1.19
Non-specified (Air Transport)	0.35	0.36	0.27	0.24	0.25	0.18	0.18	0.18	0.56	0.24	0.78	0.18	1.19
Pipeline (090)	1.27	1.62	1.69	1.61	1.35	1.47	1.62	24.40	10.40	10.72	10.72	12.26	11.07

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.89	9.03	9.51	9.48	10.67	9.40
Other than Natural Gas	1.27	1.62	1.69	1.61	1.35	1.47	1.62	1.50	1.37	1.21	1.24	1.59	1.67
Non-specified (Transport)	1.27	1.62	1.69	1.61	1.35	1.47	1.62	1.50	1.37	1.21	1.24	1.59	1.67
Petroleum	**2,576.05**	**2,499.13**	**2,560.72**	**2,514.08**	**2,604.32**	**2,628.96**	**2,663.78**	**2,686.81**	**2,763.84**	**2,816.17**	**2,897.18**	**2,885.47**	**3,016.36**
LPG (093)	3.35	2.75	2.36	2.37	3.66	2.04	1.74	1.26	2.42	1.39	5.73	6.93	3.00
Motor Gasoline (093)	1,579.69	1,542.34	1,632.02	1,605.45	1,599.51	1,629.49	1,615.52	1,624.85	1,658.92	1,705.69	1,731.34	1,764.48	1,853.77
Aviation Gasoline (093)	5.58	5.51	5.35	4.13	4.00	4.07	3.88	4.22	2.90	4.16	3.58	3.31	3.67
Jet Fuel (093)	538.12	510.66	491.52	506.01	560.16	540.38	588.39	584.83	597.54	559.48	584.02	551.22	580.08
International Jet Fuel Aviation	203.12	192.75	185.53	191.00	211.43	203.97	222.09	220.75	225.54	211.18	220.44	208.06	218.96
Domestic Aviation	335.01	317.91	305.99	315.02	348.72	336.41	366.30	364.08	371.99	348.30	363.58	343.16	361.13
Distillate (093)	317.13	314.49	314.14	288.18	327.79	340.68	342.39	370.62	373.91	388.35	418.02	409.52	424.06
Railroad	31.33	33.12	30.13	26.56	28.75	32.79	35.01	34.69	36.40	37.73	41.40	39.11	41.08
Road Transportation	252.38	245.42	255.57	253.02	275.39	289.82	293.43	317.33	324.43	340.95	365.14	364.39	374.97
Water Transportation	4.25	9.70	5.66	1.99	6.10	0.22	0.86	15.26	9.44	7.92	9.90	0.00	0.00
Non-specified (Transport)	29.17	26.24	22.79	6.61	17.56	17.86	13.10	3.34	3.64	1.75	1.58	6.02	8.01
Residual Oil (093)	16.14	13.24	9.48	9.25	11.09	14.64	13.46	7.61	6.99	9.77	11.45	10.77	10.41
Water Transportation	16.14	13.24	9.34	9.05	10.96	13.46	12.35	7.08	6.74	9.62	11.45	10.74	10.30
Non-specified (Transport)	0.00	0.00	0.14	0.21	0.14	1.18	1.11	0.53	0.25	0.15	0.00	0.03	0.11
Lubricants (129)	17.41	15.57	15.88	16.17	16.90	16.61	16.12	17.03	17.83	18.02	17.75	12.19	12.05
Marine Bunkers (Report separately in GHG Inventory)	323.67	265.48	187.26	181.46	219.72	269.87	247.71	141.98	135.14	192.97	229.62	215.05	205.25
Distillate Bunkers (005)	17.05	13.98	9.86	9.56	11.57	14.21	13.05	7.48	7.12	10.16	12.09	10.99	9.56
Residual Oil Bunkers (005)	306.62	251.50	177.40	171.91	208.15	255.66	234.66	134.50	128.02	182.81	217.53	204.06	195.69
Electricity Generation (Excludes Wood, Landfill & MSW)	**796.00**	**801.27**	**939.48**	**842.76**	**994.07**	**756.09**	**683.80**	**742.12**	**790.83**	**876.08**	**1044.09**	**1121.97**	**803.85**

Source	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Natural Gas	**689.82**	**691.54**	**826.12**	**732.62**	**875.68**	**663.03**	**590.78**	**651.23**	**706.78**	**778.45**	**941.65**	**1025.54**	**778.44**
Commercial CHP (011)	12.18	10.83	12.13	12.41	13.78	14.29	14.61	13.73	14.10	13.89	13.46	12.40	12.06
Electric CHP (012)	122.39	126.91	139.34	144.89	149.04	148.75	147.66	155.85	154.57	154.34	151.16	138.22	181.90
Industrial CHP (013)	79.29	85.54	82.88	83.55	86.11	86.72	95.72	90.05	90.59	90.08	89.58	90.89	98.80
Utility (014)	471.47	461.59	583.06	480.04	618.73	405.36	326.29	385.13	276.04	145.52	129.71	120.28	89.63
Merchant Power (015)	4.50	6.66	8.71	11.73	8.02	7.92	6.49	6.47	171.47	374.63	557.74	663.76	396.04
Other (016)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	**24.98**	**26.93**	**32.56**	**32.17**	**33.24**	**29.24**	**25.93**	**22.51**	**21.47**	**23.88**	**24.14**	**22.85**	**25.41**
Electric CHP (012)	15.16	21.33	22.65	23.71	22.53	21.40	18.35	16.77	18.37	20.48	20.67	19.25	21.73
Industrial CHP (013)	8.02	3.23	7.48	6.02	8.40	7.84	7.58	5.75	3.10	3.40	3.47	3.60	3.69
Merchant Power (015)	1.80	2.37	2.43	2.45	2.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wood & Wood Waste (exclude for carbon dioxide)	**60.33**	**62.20**	**59.75**	**55.29**	**61.93**	**40.72**	**45.66**	**45.88**	**41.31**	**51.58**	**53.12**	**49.41**	**0.00**
Landfill & MSW (exclude for carbon dioxide)	**20.87**	**20.61**	**21.05**	**22.67**	**23.22**	**23.11**	**21.42**	**22.49**	**21.27**	**22.17**	**25.18**	**24.18**	**0.00**
Not Sector-Specific; Other End Use (126)	**20.67**	**10.85**	**9.05**	**10.56**	**12.29**	**9.95**	**8.97**	**7.56**	**-2.33**	**11.28**	**16.06**	**12.82**	**12.55**
Natural Gas	20.67	10.85	9.05	10.56	12.29	9.95	8.97	7.56	-2.33	11.28	14.45	10.17	10.41
Liquefied Petroleum Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.61	2.66	2.14

APPENDIX C

DISCUSSION OF ALTERNATIVE METHODS OF ESTIMATING CARBON DIOXIDE EMISSIONS FROM ELECTRICITY IMPORTED TO CALIFORNIA

At least three approaches have been used to estimate out-of-state carbon dioxide emissions from electricity imported to California: (1) the current GHG inventory method, (2) a method used by Joseph Loyer, and described below, and (3) the method used in the 1990-1999 inventory. Energy imported to California from the Pacific Northwest and Pacific Southwest is not correlated to specific fuel types and the fuel types need to be estimated. Emissions from two out-of-state coal-fired power plants owned by California electric utilities are evaluated in the normal manner and reported as out-of-state emissions.

CURRENT GREENHOUSE GAS INVENTORY

The method used to develop the current greenhouse gas inventory is described in the main body of this paper.

Joseph Loyer Method

Joseph Loyer of the Energy Commission's Electricity Office estimated percentages of various fuels used to generate electricity for import to California for the 1994 and 1995 calendar years, and presented his results in a report titled *Fuel~Resource Profiles of Electricity Generation and Related CO_2 Emissions for The State of California, 1994 and 1995*. This report is dated April 2, 1998.

To determine CO_2 emissions from the two out-of-state coal facilities, the author used data appropriate for coal-fueled fuel combustion. To determine carbon dioxide emissions from the Pacific Northwest and Pacific Southwest, the author used data from the DOE to determine the amount of energy (measured in GWh) sold by each company to California in 1994 and 1995. He then used each company's annual percentages of GWh by fuel type each year and assumed that these percentages applied to electrical energy sold to California. From this he estimated the amount of energy in GWh by fuel type for electricity sold for use in California, and corresponding carbon dioxide emissions.

Using Loyer's data, in 1994 imported coal-based electricity comprised 18.9 percent of the total GWh imported for use in California. Using the approach described above for the current GHG inventory, in 1994 coal comprised 18.0 percent of the total GWh imported for use in California. Correspondingly, for 1995 Loyer's method yields imported coal energy comprising 17.7 percent of California's total GWh consumption while using the current GHG inventory method yields imported coal energy comprising 16.1 percent.

1990-1999 Inventory

The 1990-1999 inventory[67] also included estimates of GHG emissions from out-of-state electric power production imported to California. That analysis used the conventional approach to estimate CO_2 emissions from the out-of-state coal facilities owned by California utilities. For the remainder of the electrical energy imported to California from the Pacific Northwest and Pacific Southwest, it assumed an emissions factor of 800 metric tons CO_2 per GWh. This emissions factor was said to be uncertain because the underlying mix of fuel used to generate the GWh was unknown. This emissions factor was obtained from the Loyer reference, but with an earlier date. The April 2, 1998 version of the Loyer reference produces an emissions factor of 808 metric tons of CO_2 per GWh for 1994, and 861 metric tons of CO_2 per GWh for 1995.

This emissions factor was assumed to apply to the imports for the Pacific Northwest and Pacific Southwest for the entire 1990 to 1999 period. However, documentation in the 1990-1999 GHG emissions inventory report cautioned that the approach may overstate emissions because the total amount of GWh imported in 1994 and 1995 was relatively low compared to other years during the 1990 to 1999 period.

Summary of Options to Estimate Carbon Dioxide Emissions from Electric Imports

All three methods used conventional data and emissions factors for the two out-of-state coal fired electric power plants owned by California utilities. To estimate carbon dioxide emissions from electrical energy imported from the Pacific Northwest and Pacific Southwest, each method was different and had one or more limitations:

(1) The approach used for this inventory is based upon an Energy Commission adopted <u>estimate</u> of the fuel profile used to generate electricity imported from the Pacific Northwest and Pacific Southwest. This estimate was somewhat arbitrary, and was not officially adopted for the entire 1990 to 2000 period.

(2) The method used by Loyer was only done for 1994 and 1995, and it assumed each import providing company's annual average fuel profile applied to the electricity that California imported.

(3) The method used in the 1990-1999 inventory assumed that the fuel mix used to import electricity from the Pacific Southwest and Pacific Northwest in 1994 and 1995 matched the fuel mix for the entire 1990 to 1999 period.

Table C-1 compares these three different approaches for estimating carbon dioxide emissions from imported electricity. The Loyer approach was only done for 1994 and 1995. The current approach shows the lowest estimates for each year and the 1990-1999 inventory method shows the highest. The Loyer approach is mid range.

Table C-1. Comparing Three Methods to Estimate CO_2 Emissions from Imported Electricity (Million Metric Tons of Carbon Dioxide)

Inventory Approach	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
-Current	43.3	43.1	43.0	40.8	43.2	38.5	40.6	47.0	52.9	51.7	40.5	47.4	51.7
-Loyer					48.3	45.6							
-Previous	67.5	65.4	59.6	55.0	57.5	55.1	62.7	67.5	70.5	73.0			

Endnotes

[1] Derived from U. S. Department of Commerce, Bureau of Economic Analysis, December 15, 2004, [http://www.bea.gov/bea/regional/gsp/], (April 2005).

[2] Natural Resources Defense Council (NDRC) comments to the Energy Commission, April 5, 2005, in support of the *2005 Integrated Energy Policy Report.* NRDC cites the 1999 Energy Commission emissions inventory, estimated that in-state sources of carbon dioxide were 346 $MMTCO_2$ and out-of-state sources were 73 $MMMTCO_2$, placing California tenth in the ranking of world GHG emitting countries.

[3] NRDC comments to the Energy Commission, April 5, 2005.

[4] The term "CO_2-equivalent" is used to describe the ensemble of GHG that contribute to global warming, including carbon dioxide, methane, nitrous oxide, and a class of gases called high global warming potential gases (see separate end note for this definition). To determine carbon dioxide equivalence, carbon dioxide is given a weighting factor of 1.0 and the other gases are given a weighting factor greater than 1.0 because they have a stronger impact on global warming than carbon dioxide. These weighting factors are called "global warming factors" and are usually based upon the impact of the subject gas estimated over a 100 year period of time. These global warming factors are agreed upon in an international review process.

[5] The term "anthropogenic" is used to describe something that is human-derived rather than naturally occurring.

[6] Intergovernmental Panel on Climate Change (2001), *Climate Change 2001: Synthesis Report, Summary for Policy Makers,* page 2, http://www.grida.no/climate/ipcc_tar/vol4/english/076.htm.

[7] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[8] EPA, June 2003 and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[9] Energy Commission, August 2004, *California Energy Balances Report*, Sacramento, California, P500-04-058.

[10] EPA, June 2003 and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[11] Because it was not possible to obtain full GHG inventory data for the other states, staff used estimates of carbon dioxide emissions from fossil fuel combustion to compare California emissions to other states and to evaluate how they compare in relative GHG emissions intensity.

[12] Energy Commission, October 1990, 1988 *Inventory of California Greenhouse Gas Emissions*, Sacramento, California, Final Staff Report.

[13] Energy Commission, March 1997, *California's Greenhouse Gas Emissions Inventory 1990*, Sacramento, California, P500-97-004.

[14] Energy Commission, January 1998, *Appendix A. Historical and Forecasted Greenhouse Gas Emissions Inventories for California*, Sacramento, California, P500-98-001V3.

[15] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[16] The term "high global warming potential gases" is applied to a series of gases used in industrial processes, including perfluorocarbons, hydrofluorocarbons, and SF_6. These are mainly used as replacements for ozone-depleting industrial gases (see separate end note for definition), as byproducts of manufacturing processes, semiconductor manufacturing and electric power transmission, and distribution switchyard gear.

[17] The term "transportation" includes carbon dioxide, methane, and nitrous oxide emissions from on-road and off-road uses of petroleum and natural gas fuels. Petroleum transportation fuel use includes liquefied petroleum gas, motor gasoline, aviation gasoline, jet fuel (both domestic and international/interstate civil aviation are included at this time because the latter could not be subdivided at this time), distillate, residual oil, lubricants, and pipeline transport of fuels. Natural gas transportation fuel use includes rail, road, water, and air (most likely, this is ground support equipment at airports).

[18] The term "industrial" includes carbon dioxide emissions from coal use and petroleum use (including LPG, motor gasoline, refinery still gas, kerosene, distillate, residual oil, petroleum coke, lubricants, and special naphtha). It also includes industrial activities that produce carbon dioxide directly from their production or use, including cement production, lime production, limestone and dolomite consumption, soda ash consumption, and waste combustion. Industrial GHGs also include methane emissions from petroleum and natural gas extraction, transmission, storage and marketing; landfill emissions; waste water treatment; and industrial fuel combustion. Industrial GHGs also include nitrous oxide emissions from waste combustion; municipal waste (formerly called "human waste"); and industrial fuel use, including wood. Finally, industrial GHGs also include high global warming potential gases used as substitutes for ozone-depleting gases (see definition in separate note) and in semiconductor manufacture. Because the trend analysis is based upon gross emissions to the degree possible, emissions reductions from yard trimmings and lumber disposal and associated increased carbon dioxide emissions atmosphere are excluded.

[19] The term "electricity production" includes carbon dioxide emissions from in-state natural gas and coal combustion, out-of-state coal-fired power plants owned by California utilities, and coal and natural gas fueled imported energy purchases; methane emissions from fossil fuel combustion; nitrous oxide emissions from fossil fuel and wood combustion; and $SF_6$from electricity transmission and distribution.

[20] The term "agriculture" includes carbon dioxide emissions from natural gas used in crop production, livestock production and irrigation; rangeland, woody crop, and non-woody crop management and soil liming. Agricultural greenhouse gases also include methane emissions from enteric fermentation, manure management, rice field flooding, and agricultural burning. Agricultural greenhouse gases also include nitrous oxide emissions from manure management and agricultural residue burning. Because the trend analysis is based upon gross emissions to the degree possible, emissions reductions from expanding rangelands and associated increased carbon dioxide removal from the atmosphere are excluded.

[21] The term "forestry" includes carbon dioxide emissions from forestry management. Because the trend analysis is based upon gross emissions to the degree possible, emissions reductions from expanding forestry management and associated increased carbon dioxide removal from the atmosphere are excluded.

[22] The term "commercial" includes carbon dioxide emissions from coal, petroleum (includes LNG, motor gasoline, kerosene, distillate, and residual oil), and natural gas (includes education, food

services, retail, and wholesale, healthcare, hotel, office, transportation services, communication, utilities excluding electricity production, national security, and non-specified services), and non-specified fuel uses. Commercial greenhouse gas also include methane emissions from petroleum, natural gas, wood and non-specified fuel use; and nitrous oxide emissions from coal, petroleum, natural gas, and wood use.

[23] The term "residential" includes carbon dioxide emissions from liquefied natural gas, kerosene and distillate; methane emissions from petroleum, natural gas, and wood; and nitrous oxide emissions from coal, petroleum, natural gas, and wood.

[24] The term "residual oil" is applied to one of the distilled products from refining crude oil. Residual oil is the heavy residue that remains in liquid form after more valuable products such as gasoline and distillate are recovered. It is often used as an industrial fuel. CARB regulations often preclude its use in California.

[25] The trend analysis includes out-of-state GHG emissions because energy policy decisions made by the State of California, including the Energy Commission, will affect emissions both within the state and outside the state. GHG inventory guidelines established by the International Panel on Climate Change (IPCC) and by the EPA do not require reporting emissions from within one political boundary that that supply energy to another political entity. Thus, out-of-state GHG emissions do not need to be considered when developing GHG inventories. Out-of-state GHG emissions from electricity production are reported separately from in-state emissions in the GHG inventory. As noted elsewhere in this document, in-state GHG emissions for electricity exported are negligible. Policy decisions in other end-use sectors such as petroleum fuel use should consider out-of-state emissions affected by the policy decision to the extent possible.

[26] The category "Other Transportation Fuels" includes carbon dioxide from liquefied petroleum gas, distillate, residual oil, and lubricating oil; nitrous oxide from diesel fuel and aviation gasoline; and other minor sources.

[27] These "other" emissions are carbon dioxide emissions from fuel end-uses not specified in the *California Energy Balances Report*.

[28] Ozone depleting gases are a class of industrial gases that are being used in increasing quantities to mitigate the high-level ozone holes over the Earth's.

[29] The *California Energy Balances Report* indicates a small amount of coal is combusted in utility and industrial combined heat and power facilities.

[30] Executive Order S-3-05, June 1, 2005, http://www.governor.ca.gov/state/govsite/gov_htmldisplay.jsp?BV_SessionID=@@@@1044157704.1119371305@@@@&BV_EngineID=cccdaddemgghlmicfngcfkmdffidfng.0&iOID=69591&sTitle=Executive+Order+S-3-05&sFilePath=/govsite/executive_orders/20050601_S-3-05.html&sCatTitle=Exec+Order, June 21, 2005.

[31] California's carbon dioxide emissions from fossil fuel combustion comprise about 83 percent of total GHG emissions when imported electricity is excluded or about 84 percent when imported electricity is included. The percentage changes very little over the1990 to 2001 period. These percentages are consistent with the percent gas composition for Washington (81 percent in 1990, and 85 percent in 2000), Connecticut (90.5 percent in 2000), Pennsylvania (90.3 percent in 1999) and Michigan (86.2 percent in 1990, and 86.5 percent in 2002) but somewhat greater than Iowa (79.5 percent in 1990, and 67.1 percent in 2000) and Oklahoma (58.9 percent in 1990, and 58.2 percent in 1999). Percentages were not found for other states.

[32] U. S. Department of Commerce, Bureau of Economic Analysis, December 15, 2004, [http://www.bea.gov/bea/regional/gsp/], (April 2005).

[33] Although Texas is at the top of Figure 5, it is in the middle of Figure 6. California's gross emissions are second from the top in Figure 5 but near the bottom of Figure 6. On the other hand, Wyoming is near the bottom of Figure 5, but at the top of Figure 6.

[34] The term GSP means the total value of the goods and services produced by the residents of the state during a specific period, such as a year.

[35] Intergovernmental Panel on Climate Change (2001), *Climate Change 2001: Synthesis Report, Summary for Policy Makers,* page 2, [http://www.grida.no/climate/ipcc_tar/vol4/english/076.htm].

[36]EPA, June 2003 and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[37] Ibid.

[38] Energy Commission, August 2004, *California Energy Balances Report*, Sacramento, California, P500-04-058.

[39]EPA, June 2003, and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[40] Ibid.

[41] This can be found in Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, [http://www.energy.ca.gov/reports/600-02-001F/index.html], Table 14.

[42] Intergovernmental Panel on Climate Change (2001), *Climate Change 2001: Synthesis Report, Summary for Policy Makers,* page 2, [http://www.grida.no/climate/ipcc_tar/vol4/english/076.htm].

[43] EPA, June 2003, and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[44] These are the Intermountain Power Plant and the Mohave Power Plant.

[45] This adjustment accounts for the molecular weight of carbon dioxide (CO_2=44) and lime (CaO=56).

[46] Limestone uses as flux (or purifier) in metallurgical furnaces, glass manufacturing, and flue gas desulfurization processes do not produce carbon dioxide emissions.

[47] EPA, June 2003, and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[48] Energy Commission, March 2004, *Baseline Greenhouse Gas Emissions for Forest, Range, and Agricultural Lands in California*, Sacramento, California, P500-04-069, http://www.energy.ca.gov/pier/final_project_reports/500-04-069.html.

[49] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[50].CIWMB, December 2004, Statewide Waste Characterization Study, Sacramento, California.

[51] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[52] CARB, April 2005, *Areawide Source Methodologies,* (dynamic dating), [www.arb.ca.gov/ei/areameth.htm].

[53] CARB, April 2005, Emissions Inventory Methods, Speciation and Size Fractions, [http://www.arb.ca.gov/ei/speciate/speciate.htm], (July 28, 2004).

[54] Ruminant animals re-chew food that has been swallowed and usually have a four-chamber stomach.

[55] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[56] Ibid.

[57] EPA, June 2003 and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC.

[58] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[59] Ibid.

[60]EPA, June 2003, and subsequent updates, *Introduction to Estimating Greenhouse Gas Emissions,* November 2002, Washington, DC

[61] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[62] Ibid.

[63] Ibid.

[64] Ibid.

[65] EPA, January 2004, *Reducing SF_6 Emissions Means Better Business for Utilities,* Office of Atmospheric Programs, www.epa.gov/electricpower-sf6.

[66] Energy Commission, November 2002, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999,* Sacramento, California, P600-02-001F, http://www.energy.ca.gov/reports/600-02-001F/index.html.

[67] Ibid.

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