New Mexico Greenhouse Gas Inventory and Reference Case Projections

Prepared for the:

New Mexico Environment Department

The Center for Climate Strategies

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Acronyms and Key Terms

AEO2005 – US DOE Energy Information Administration's Annual Energy Outlook 2005
BCF – Billion cubic feet
BLM – Bureau of Land Management
CBM – Coal-bed Methane
CH4 – Methane*
CO2 – Carbon Dioxide*
CO2e – Carbon Dioxide equivalent*
EIA – US DOE Energy Information Administration
EMNRD - Energy, Minerals and Natural Resources Department
FIA – Forest Inventory Analysis (US Forest Service)
FHWA – Federal Highway Administration
GHG – Greenhouse Gases*
GNP – Gross National Product
GSP – Gross State Product
GWP - Global Warming Potential*
GWh – Gigawatt-hours (1 million kilowatt-hours)
HFCs – Hydrofluorocarbons*
IPCC – Intergovernmental Panel on Climate Change*
KWh – Kilowatt-hour
Mt - Metric ton (equivalent to 1.102 short tons)
MMt – Million Metric tons
MTBE – Methyl Tertiary Butyl Ether
MWh – Megawatt-hours (1 thousand kilowatt-hours)
NMED – New Mexico Environment Department
NMDOT – New Mexico Department of Transportation
NMOGA – New Mexico Oil and Gas Association
N2O – Nitrous Oxide*
ODS – Ozone-Depleting Substances
PFCs – Perfluorocarbons*
PNM – Public Service of New Mexico
RCI – Residential, Commercial, and Industrial
RPS – Renewable Portfolio Standard
SEDS – US DOE Energy Information Administration's State Energy Data System
SGIT – US EPA State Greenhouse gas Inventory Tool
SF6 – Sulfur Hexafluoride*
Sinks – Removals of carbon from the atmosphere, with the carbon stored in forests, soils, landfills, wood structures, or other biomass-related products.
US EPA – US Environmental Protection Agency
US DOE – US Department of Energy
TWh – Terawatt-hours (1 billion kilowatt-hours)
VMT – Vehicle-miles Traveled
WRAP – Western Regional Air Partnership

* - See Appendix I for more information.

Acknowledgements

We appreciate all of the time and assistance provided by numerous contacts throughout New Mexico, as well as in neighboring states, and at federal agencies. Most of these contacts are listed in Appendix H – our apologies to those not yet listed, as we recognize this list is far from complete. Thanks go to in particular the many staff at several New Mexico state agencies for their inputs, and in particular to Lany Weaver and Brad Musick of the New Mexico Environment Department who provided key guidance for this analytical effort.

1. Summary of Findings

Introduction

This report presents initial estimates of historical and projected New Mexico anthropogenic greenhouse gas (GHG) emissions and sinks for the period from 1990 to 2020. These estimates are intended to assist the State, stakeholders and technical work groups with an initial comprehensive understanding of current and possible future New Mexico greenhouse gas (GHG) emissions, and thereby inform the upcoming analysis and design of GHG mitigation strategies.

Historical GHG emissions estimates (1990 through 2003)[1] were developed using a set of generally-accepted principles and guidelines for State greenhouse gas emissions, as described in Section 2, relying to the extent possible on New Mexico-specific data and inputs.[2] The initial reference case projections out to 2020 are based on a compilation of various existing New Mexico and regional projections of electricity generation, fuel use, and other GHG emitting activities, along with a set of simple, transparent assumptions described later in this report. These estimates should be viewed as a preliminary input to the New Mexico Climate Change Advisory Group (NMCCAG) process; many data sources and experts have not yet been tapped and some sectors are still undergoing further assessment. Input and suggestions are welcomed.

This report covers the six types of gases included in the US Greenhouse Gas Inventory: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). Emissions of these greenhouse gases are presented using a common metric, CO2 equivalence (CO2e), which indicates the relative contribution of each gas to global average radiative forcing on a Global Warming Potential (GWP) weighted basis. The final appendix to this report provides a fuller discussion of greenhouse gases and GWPs.

New Mexico Greenhouse Gas Emissions: Sources and Trends

Initial analysis suggests that in 2000, New Mexico produced about 83 million metric tons[3] (MMt) of *gross* carbon dioxide equivalent (CO2e) emissions, an amount equal to 1.2% of total *gross* US GHG emissions.[4] Gross emissions include all major sources and gases, most notably

[1] For some sectors and sources, historical data are only available through 2000, 2001 or 2002.

[2] A starting point for this analysis was the 1996 New Mexico GHG emissions inventory prepared by the Waste Management Education and Research Consortium (WERC) as part of *New Mexico Greenhouse Gas Action Plan: Enhancing our Future through Mitigation* (WERC 2002). This report included a single historical year (1996) and a more limited set of emissions sources and gases than included here. WERC is a consortium of the New Mexico State University, the University of New Mexico, the New Mexico Institute of Mining and Technology, and Diné College in collaboration with Sandia National Laboratories and Los Alamos National Laboratory.

[3] All GHG emissions are reported here in metric tons.

[4] United States emissions estimates are drawn from Climate Analysis Indicators Tool (CAIT) version 1.5. (Washington, DC: World Resources Institute, 2003), which is based on official USEPA reports. Available at: http://cait.wri.org.

the combustion of fossil fuels in power plants, vehicles, buildings, and industries (82% of total State emissions), the release of methane from oil and gas production, coal mines, agriculture, and waste management (13%), and other sources such industrial processes and nitrous oxide from agricultural soils (5%).

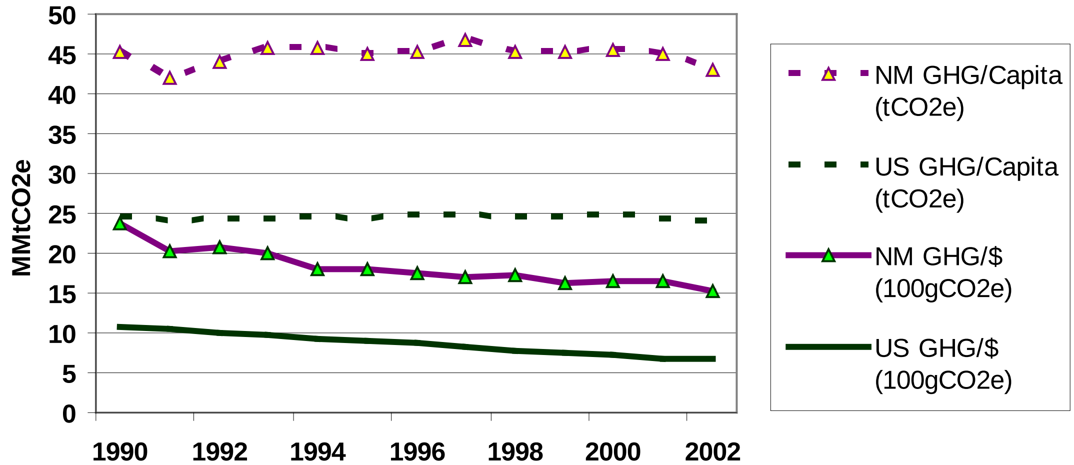
Net emissions combine gross emissions sources with carbon sequestered and released from biomass throughout the State. Very preliminary estimates suggest that from the late 1980s through the late 1990s, New Mexico's forest areas sequestered about 21 MMtCO2e per year. If these estimates are applied to 2000, the State's *net* GHG emissions would be 62 MMtCO2e, about 25% lower than the gross emissions estimate. However, there are rather large uncertainties regarding changes in carbon stocks in New Mexico forestlands since 1997, the year that the US Forest Service conducted its most recent forest inventory in the State, especially given drought and disease conditions since that time. Therefore, we focus most of this section on gross emissions sources, for which there is greater certainty. Net emissions are also shown below, using the only historical estimates available as a placeholder until better estimates are available.

The State's gross GHG emissions increased by about 21% during the 1990s, somewhat slower than the US as a whole, where emissions rose by 23%. This slower increase appears largely attributable to a few key factors, in particular limited growth in new power generation facilities and the decline of the mining industry and its fuel and electricity requirements. Were it not for these factors, New Mexico's emissions could well have increased as fast as, or faster than, the national average, given the State's more rapid population and economic growth.[5] Transportation-related GHG emissions, which are driven directly by fuel use and in turn by population, rose by 29% in the 1990s, and represent one of the State's fastest growing GHG emissions sources.

On a per capita basis, New Mexico produces near twice the GHG emissions as the national average (45 vs. 25 tCO2e per person). New Mexico's high per capita emissions are largely the result of its GHG-intensive gas, oil, and electricity production industries. Figure 1 shows that, like the nation as a whole, per capita emissions have remained fairly flat, while economic growth outpaced emissions growth throughout the 1990-2002 period. During the 1990s, gross GHG emissions per unit of gross product dropped by 33% nationally, and by 31% in New Mexico.

[5] During the 1990s, population grew by 20% in New Mexico compared with 13% nationally, and state GSP grew by 76% compared with national GDP growth of 72%.

Figure 1. New Mexico and US GHG Emissions, Per Capita and Per Unit Gross Product (2000$)



In addition to being a key facet of the State's economy, as noted, energy producing industries are the dominant feature of New Mexico's GHG emissions profile. Together, the production of electricity and fossil fuels accounted for two-thirds of New Mexico's gross GHG emissions in the year 2000, as shown in Figure 2. In comparison, these activities accounted for only 35 to 40% of national gross GHG emissions.[6]

Emissions of greenhouse gases by electric power plants, the State's leading emission source, are relatively well understood, and are for the most part (carbon dioxide at facilities over 25 MW) continuously monitored. Over 90% of these emissions occur at the State's coal-fired facilities, and two plants, San Juan and Four Corners, account for about three-quarters. Natural gas-fired power plants produce the remaining emissions from this sector.

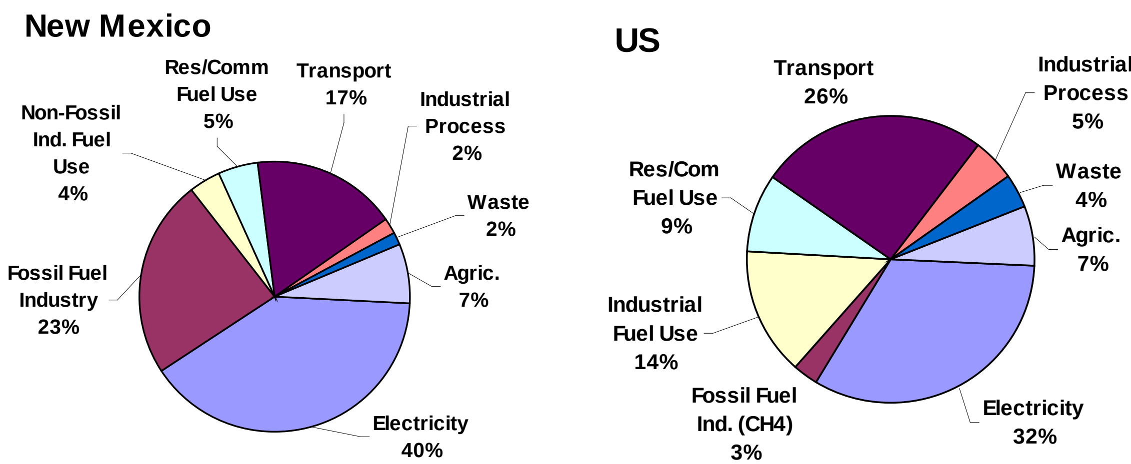
Emissions of carbon dioxide and methane occur at many stages of the fossil fuel production and delivery process (drilling, production, processing/refining, and pipeline transport), and can be highly dependent upon local resource characteristics (e.g., pressure, depth, water content, gas concentrations), technologies applied, and practices employed at individual wells sites and compressor stations. With over 40,000 oil and gas wells, three oil refineries, several gas processing plants, and tens of thousands of miles of gas pipelines in the State – and no regulatory requirements to track CO_2 or CH_4 emissions – there are significant uncertainties with respect to the State's GHG emissions from this sector.

Preliminary estimates however, suggest that fossil fuel industry emissions are quite high. The majority of emissions come from natural gas production, with significant emissions resulting from fuel use at field sites, processing plants, and pipelines (6 MMtCO2), the release of associated CO2 found in the coalbed methane from the Fruitland field in the San Juan Basin (5

[6] Fuel use for field, processing, and pipeline operations are included in the fossil fuel industry for New Mexico; however, such fuel use is not disaggregated in the national inventory, and thus constitutes a fraction of the slice shown for US industrial fuel use.

MMtCO2), and methane vented and flashed at well sites, processing plants, and pipelines (5 MMtCO2e). Further analysis is needed to resolve some of the large unknowns regarding these and other oil and gas sector emissions.

Figure 2. Gross GHG Emissions by Sector and Gas, 2000, New Mexico and US



As a fraction of total GHG emissions, transportation accounted for 17% of New Mexico emissions, compared with 26% of national emissions. However, on a per capita basis, New Mexicans actually consume more gasoline and diesel fuel, and produce more transportation-related GHG emissions, than the average American.

The remaining use of fossil fuels – natural gas, oil products, and coal -- constitutes another 9% of State emissions, about half in residential and commercial buildings and the other half among non-fossil-fuel industrial (RCI) sectors. While GHG emissions from residential and commercial fuel use grew about 10% from 1990 to 2000, industrial fuel use grew in the early 1990s, but has since declined, most likely a reflection of reducing mining and smelting activity in the State.

Agricultural activities such as manure management, fertilizer use, and livestock (enteric fermentation) result in methane and nitrous oxide emissions that account for 7% of State GHG emissions. These emissions grew by over 30% from 1990 to 2000, the result of rapidly expanding dairy operations in the State.

Industrial process emissions comprise about 2% of State GHG emissions today. Three sources each account for about one-third of these emissions in the year 2000: the use of hydrofluorocarbons (HFCs) as substitutes for ozone-depleting substances (ODS) such as chlorofluorocarbons and hydrochlorofluorocarbons[7], the use of perfluorocarbons (PFC) in semiconductor manufacture, and carbon dioxide released during the calcination process in cement production. Since the year 2000, efforts by semiconductor industries, Intel, in particular,

[7] Chlorofluorocarbons and hydrochlorofluorocarbons are also potent greenhouse gases; however they are not included in GHG estimates because of concerns related to implementation of the Montreal Protocol. See final Appendix.

have led to substantial reductions in PFC emissions. However, the increasing use of HFCs is leading to rapid growth in this emissions category.

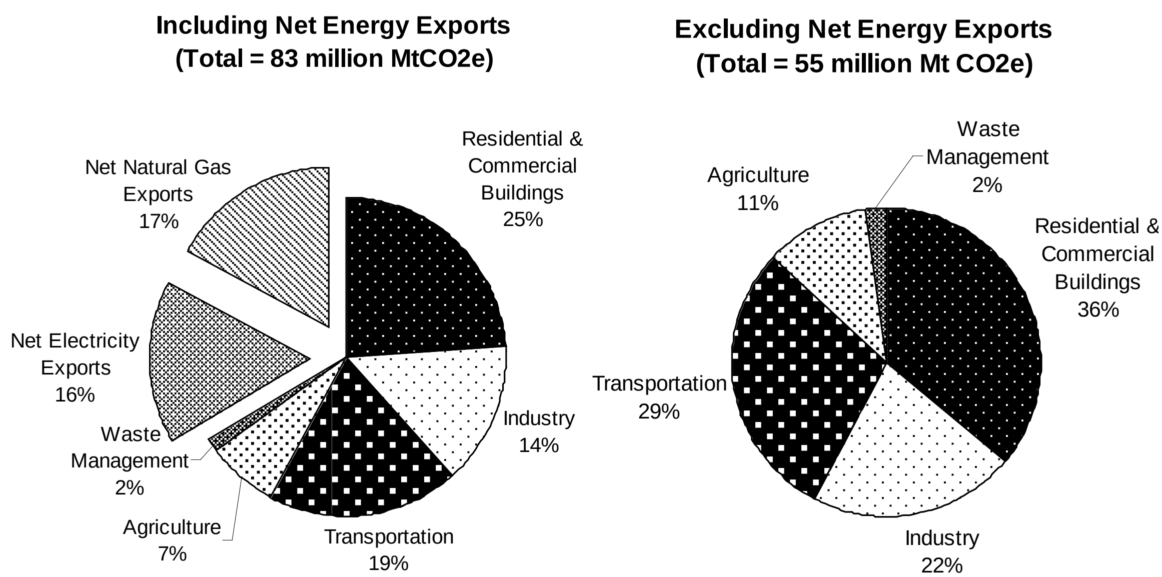
Landfills and wastewater management facilities produce methane and nitrous oxide emissions accounting for the remaining 2% of current State emissions in 2000. These emissions have increased slightly in recent years with increased landfilled waste; however, they have begun to stabilize and decline as landfill gas is increasingly captured and flared or used for energy purposes.

Box 1: Another Way to Look at New Mexico Greenhouse Gas Emissions

During the review of the draft inventory, members of the Residential, Commercial, and Industrial Technical Working Group suggested another, useful representation of the state's GHG emissions. The figures below illustrate the state's emissions by economic sector, incorporating the emissions associated with delivering electricity and fossil fuels used by these sectors. This gives a sense of the contributions of activity in each sector to overall emissions, as well as the level of effort that might be needed to achieve overall emissions reductions in line with state goals.

The left hand pie chart shows that, of the state's estimated 83 million MtCO2e of GHG emissions in 2000, about one-third was associated with electricity and natural production in excess of state consumption levels ("net exports"). Excluding these slices, and looking only at the in-state sectors, the right hand pie chart shows that of the remaining 55 million MtCO2e in GHG emissions, about 36% are associated with residential and commercial building energy consumption, 22% with industrial energy consumption and process GHG emissions, 29% with transportation fuel use, 11% with agricultural activities, and 2% with waste management emissions. (It was further noted by the RCI Technical Working Group that some industrial GHG emissions, e.g. from steel or cement production, are influenced by the design of, and materials used in, residential and commercial buildings.)

Figure 3. Representation of NM GHG Emissions by Consuming Sector

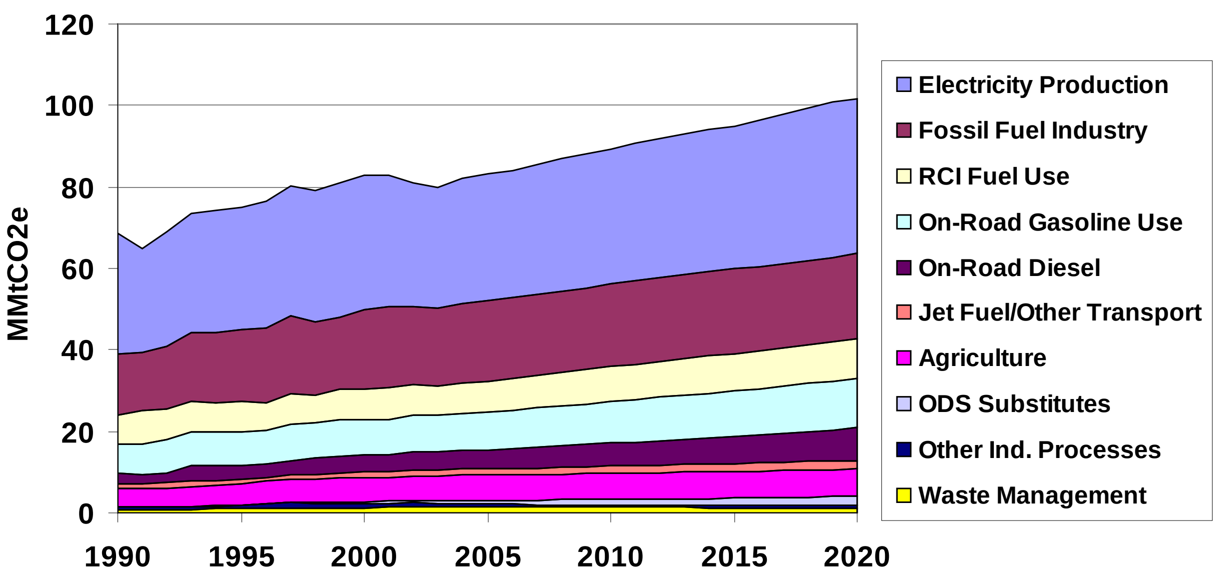


Reference Case Projections

Relying on US DOE and New Mexico agency projections of population, employment, and electricity use, input from NMED staff and industry experts, we developed a simple reference case projection of GHG emissions through 2020.[8] The reference case assumes a continuation of current trends and reflects, to the extent possible, power plants under construction and the implementation of recently enacted policies, such as the State's Renewable Portfolio Standard, which currently requires investor-owned utilities to provide 10% of the electricity sales from renewable sources by 2011.[9] As reference case projections are finalized through collaboration with stakeholders and technical work groups, it will be important to consider other existing and planned actions, as well as the basic assumption underlying these projections (See Table 3 below and further information in the Appendices).

As illustrated in Figure 3 and shown numerically in Table 1, under the reference case projection, New Mexico's gross GHG emissions are projected to grow steadily from recent levels. (For more details on emissions by source, see Table 5 at the end of this section.) By 2010 they would reach 89 MMtCO2e, 8% above year 2000 levels. By 2020, they would climb another 14% to 102 MMtCO_2e, which corresponds to a total increase of 23% above year 2000 levels. These decadal increases would be slower than New Mexico's 21% increase in GHG emissions from 1990 to 2000.

Figure 4. Gross GHG Emissions by Sector, 1990-2020: Historical and Projected



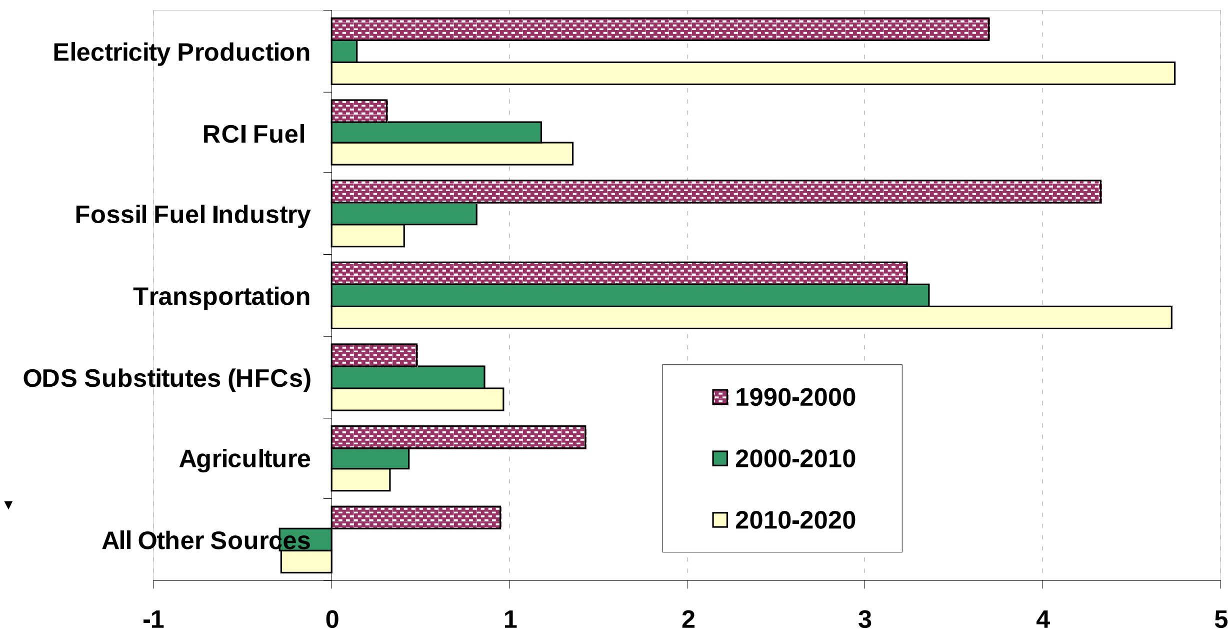
[8] Historical data runs through 2001 to 2003 depending on the emissions source.
[9] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NM05R&state=NM&CurrentPageID=1

Table 1. New Mexico GHG Emissions, Reference Case – Production Based

(Million Metric Tons CO2e)	1990	2000	2010	2020
Energy	**62.6**	**74.2**	**79.7**	**90.9**
Electricity Production	29.5	33.2	33.3	38.1
Transportation Fuel Use	11.0	14.2	17.6	22.3
Fossil Fuel Industry	15.2	19.5	20.3	20.7
Res/Comm/Other Ind. Fuel Use	7.0	7.3	8.5	9.9
Other	**5.9**	**8.7**	**9.7**	**10.8**
Industrial Processes	0.5	1.5	2.0	2.8
Agriculture	4.5	6.0	6.4	6.7
Waste Management	0.8	1.2	1.4	1.2
Gross Emissions	**68.5**	**82.9**	**89.4**	**101.7**
change relative to 1990		*+21%*	*+31%*	*+48%*
change relative to 2000			*+8%*	*+23%*
Forestry and Land Use	***-20.9***	***-20.9***	***-20.9***	***-20.9***
Net Emissions (includes Forestry and Land Use)	**47.6**	**62.0**	**68.5**	**80.8**
change relative to 1990		*+30%*	*+44%*	*+70%*
change relative to 2000			*+11%*	*+30%*
Per Capita Gross Emissions (Mt)	45	46	42	43
Per Capita Net Emissions (Mt)	31	34	32	34

These different rates of rate growth by decade can be explained by looking more closely at changes by sector, as shown in Figure 4.

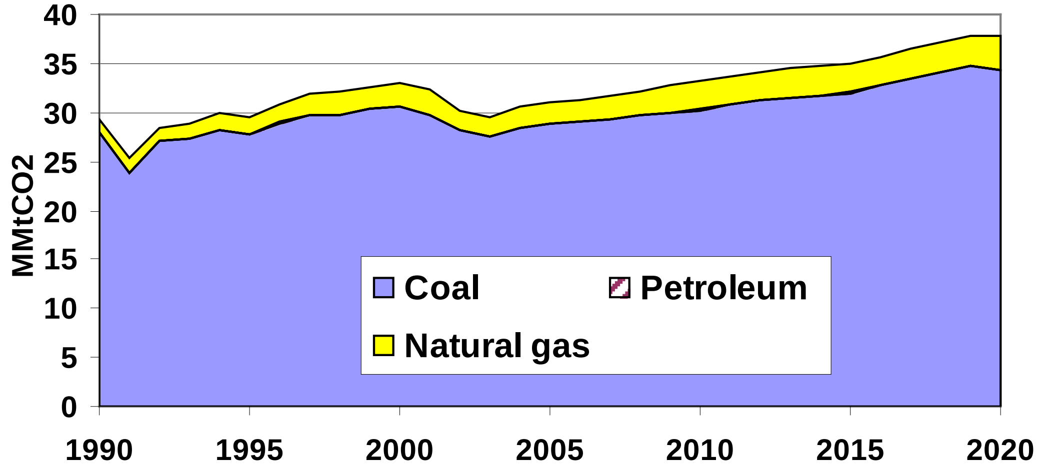
Figure 5. Contributions to Emissions Growth, 1990-2020: Reference Case Projections (MMTCO2e)



As shown, electricity production emissions grew significantly from 1990 to 2000, as existing coal plants increased production and two new power plants came on line.[10] The year 2000 was also the time of the Western power crunch, where drought conditions on the West Coast, and other market factors led to increase demands for power on the Western grid system. Electricity production has since declined, and only recently returned to 2000 levels. With much of new electricity capacity this decade expected to come from natural gas and wind facilities, growth in statewide electricity emissions is likely to be limited. However, during the 2010-2020 period, with gas prices rising and several new coal plants being proposed, electricity emissions could rise rapidly again, as illustrated in Figure 5 below.

[10] Increased generation from existing plants accounted for 90% of the increase in emissions from 1990 to 2000. Generation from the Four Corners coal plant did not change significantly, however generation at the San Juan coal plant increased by 33%, Escalante generation increased by 20%, and Rio Grande generation almost doubled. The Delta Person plant came on-line in 2000 (150MW) and the Milagro cogeneration unit in 1996 (61 MW). Note that CO2 emissions from biomass-fired combustion are not counted as net GHG emissions, consistent with USEPA and UNFCCC practices. To the extent that use of biomass energy leads to changes in carbon stocks in farms and forests, these standard methods suggest that this should be captured in forest and land use accounting.

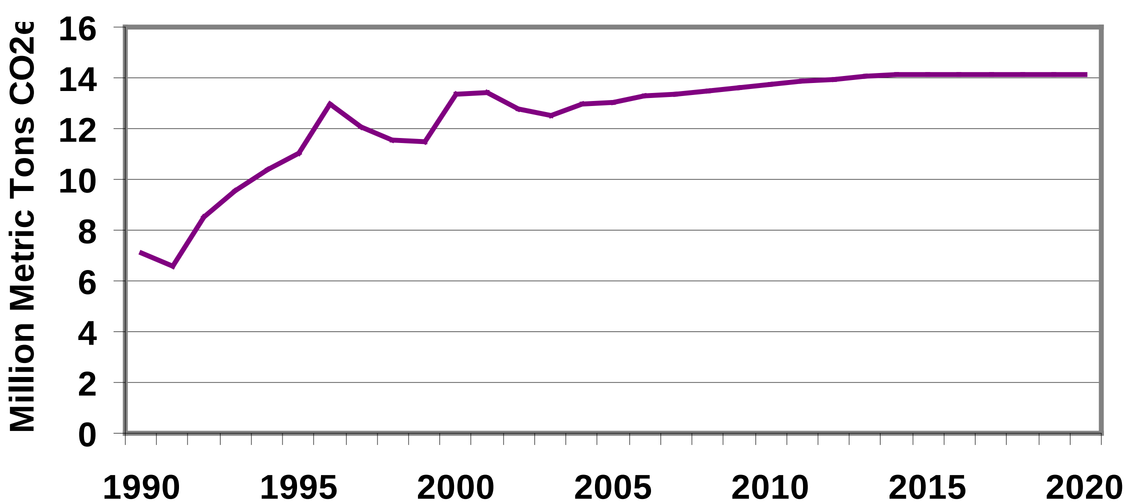
Figure 6. CO2 Emissions from Electricity Production in New Mexico, by Fuel Source



Fossil fuel industry emissions grew rapidly in the 1990s with total natural gas production rising from 1015 billion cubic feet in 1990 to 1802 billion cubic feet in 2000. Natural gas production has dropped slightly since 2000. The future of New Mexico natural gas and oil production is highly uncertain, dependent on global price trends, discovery of new reserves, and other factors. For projection purposes, we assume that new reserves will be found and exploited such that recent production levels of oil and gas will be maintained.[11]

The implication of this forecast in terms of GHG emissions is illustrated in Figure 6 below. This chart shows GHG emissions from the natural gas production and processing stages, the principal emissions sources for the oil and gas industry, and those most likely to be affected by future changes in production. GHG emissions from gas production and processing activities remain relatively constant from 2003 onward, with a slight increase owing to the increasing concentration of CO2 over time in coalbed methane production.

Figure 7. GHG Emissions from Natural Gas Production and Processing



[11] This Energy Supply Technical Working Group reviewed and affirmed this assumption for projection purposes.

As Figure 4 shows, the transportation sector is expected to be the leading source of overall GHG emissions growth from 2000 onward. Under the assumptions described in the transportation section (Appendix C), increasing diesel use for freight transport is projected to account for nearly half of this growth (3.7 MMtCO2e from 2000 to 2020). Increasing gasoline use would account for nearly as much growth (3.5 MMtCO2e), driven largely by State population growth, while rising jet fuel use would account for the remainder (0.8 MMtCO2e).

Other key sources of emissions growth include direct use of fuels in the residential, commercial, and non-fossil fuel industrial sectors, the switch to use of HFCs as substitutes for ozone-depleting substances, and methane emissions from dairy herds.

Consumption vs. Production-Based Emissions

As noted, New Mexico's emissions are well above the national average largely because of coal-based electricity generation and natural gas production activities, a significant fraction of which meets needs in other states. This situation raises an important question with respect to how these emissions should be addressed from an accounting and policy basis. In other words, should states focus on: a) all emissions produced within the State (*production-based emissions*), or b) the emissions associated with production of electricity, natural gas, and/or other energy-intensive products consumed within the State (consumption-based emissions).

Reporting production-based emissions has the advantages of simplicity and consistency with typical inventory methods. If used for policy purposes, e.g. for setting emission reduction goals and tracking progress in meeting them, production-based reporting will account for changes in emissions resulting from new in-state power plants or gas production facilities, even if such facilities are built largely to serve out-of-state consumption. Conversely, future declines in natural gas production, due for example to the depletion of gas reserves as noted, could lead to significant reductions in reported State emissions related to gas production activities. Such changes in the State's reported emissions could be very significant, and but may also be rather difficult to predict or manage. Furthermore, one could argue that these changes do not reflect "real" emissions changes, if electricity or gas consumers would otherwise source their electricity or gas from similar sources in other states or countries.

In contrast, reporting consumption-based GHG emissions can be more complex from an accounting perspective. However, the consumption-based approach may also better reflect the emissions (and emissions reductions) associated with consuming activities occurring within the State, particularly with respect to electricity use (and efficiency improvements), and is thus may be useful in a policy context. Under this approach, emissions associated with electricity exported to other states would need to be covered in those states' accounts in order to avoid double counting or exclusions. (Indeed, California, Oregon, and Washington are currently considering such an approach, as noted in Appendix A.) The consumption-based approach also leads to projections that are likely to be less volatile (subject to major changes), and future GHG emissions are perhaps more directly influenced by state-based policy strategies such as energy efficiency on overall emissions. However, as described in the electricity section (Appendix A), developing a robust tracking system for a consumption-based approach could be rather challenging.

For this initial inventory, we prepared simplified consumption-based estimates for electricity and fossil fuel production activities. For each of these energy sources, we estimated the ratio of in-State consumption to total production, and applied this ratio to the total GHG emissions from that sector. (See Table 4) While this method may not precisely reflect the sources of electricity or fuels used to meet in-state demands, it does provide a rough guide.

The result of these calculations is shown in Table 2 below. Emissions related to electricity use are about 30-40% lower than for electricity production, reflecting the fact that the State produces about 30-40% more electricity than it needs for its own use. For the fossil fuel industry, emissions attributable to in-state use are only about one-third to one-quarter of total emissions produced. This ratio is so low because most of the emissions are related to natural gas production, and the State consumes only 1 BCF of gas for every 5 or 6 BCF it produces.

Table 2. New Mexico GHG Emissions, Reference Case – Consumption Based

(Million Metric Tons CO2e)	1990	2000	2010	2020
Energy	**39.2**	**46.7**	**54.3**	**66.6**
Electricity Use	15.8	19.7	21.4	26.4
Transportation Fuel Use	11.0	14.2	17.6	22.3
Fossil Fuel Industry	5.4	5.4	6.8	8.1
Res/Comm/Other Ind. Fuel Use	7.0	7.3	8.5	9.9
Other	**5.9**	**8.7**	**9.7**	**10.8**
Industrial Processes	0.5	1.5	2.0	2.8
Agriculture	4.5	6.0	6.4	6.7
Waste Management	0.8	1.2	1.4	1.2
Gross Emissions	**45.1**	**55.4**	**64.0**	**77.3**
change relative to 1990		*+23%*	*+42%*	*+72%*
change relative to 2000			*+16%*	*+40%*
Forestry and Land Use	***-20.9***	***-20.9***	***-20.9***	***-20.9***
Net Emissions (incl. forestry)	**24.2**	**34.5**	**43.1**	**56.4**
change relative to 1990		*+43%*	*+78%*	*+134%*
change relative to 2000			*+25%*	*+64%*
Per Capita Gross Emissions	30	30	30	32
Per Capita Net Emissions	16	19	20	24

Key Uncertainties and Next Steps

Efforts are ongoing to resolve key data gaps and uncertainties in the inventory and projections. Key tasks, among others, include the incorporation of anticipated actions and policies (efficiency programs, voluntary actions such as those of the oil and gas industries through the USEPA GasStar program, etc.), a better understanding of the electricity generation sources currently used to meet New Mexico loads (in collaboration with State utilities), closer review of the many sources of oil and gas sector emissions, and review and revision of key drivers such as the electricity growth rates and future oil and gas production that will be major determinants of New Mexico's future GHG emissions (See Table 3). These growth rates are driven by uncertain economic, demographic, and land use trends (including growth patterns and transportation system impacts), all of which deserve closer review and discussion.

Table 3. Key Annual Growth Rates, Historical and Projected

	Historical 1990-2000	Projected 2000-2020	Sources/Uses
Population*	1.8%	1.4%	New Mexico Department of Labor, 2004. New Mexico Annual Social and Economic Indicators
Employment*	2.4%	2.1%	
Electricity sales	3.1%	2.5% from 2002 on	EIA SEDS for historic, projections based on EMNRD input.
Electricity production	1.6%	2.2% from 2004 on	Based roughly on AEO 2005 for the region; subject to very large uncertainties
Personal Vehicle Miles Traveled*	2.9%	1.9%	New Mexico 2025 Statewide Multimodal Transportation Plan (historical from FHWA Transportation Statistics)
Freight Vehicle Miles Traveled*	6.9%	3.6%	

* Population, employment and VMT projections for New Mexico were used together with US DOE's Annual Energy Outlook 2005 projections of changes in fuel use on a per capita, per employee, and per VMT, as relevant for each sector. For instance, growth in New Mexico residential natural gas use is calculated as the New Mexico population growth times the change in per capita New Mexico natural gas use for the Mountain region. New Mexico population growth is also used as the driver of growth in cement production, soda ash consumption, solid waste generation, and wastewater generation.

In addition, the following three areas are subject to considerable uncertainty, not simply because the future is hard to predict, but because of data availability and scientific understanding:

- **Oil and gas sector emissions:** As noted above, the sheer number and diversity of different GHG-emitting activities, combined with the fact that GHG emissions are typically unmonitored, means that there is significant uncertainty with regard to emission levels. Local estimates of field gas use and provided by NMOGA suggest the top-down estimates of natural gas production-related emissions provided here (based on national average emission rates) may be low. Furthermore, CO_2 emissions that may occur as the result of CO_2 mining and use for enhanced oil recovery could be significant, but have not been estimated. Further analysis of emissions from activities in all of the State's principal gas and oil basins, as well as of emissions from transmission and distribution sources could help to resolve some of these uncertainties. Given the large emission reduction potential that may exist in these sectors, such efforts could be quite valuable.

- **Terrestrial carbon emissions and sinks:** The net forest and land use sequestration estimates noted above are based on recent improvements to US Forest Service carbon stock inventory data but do not fully address all issues that impact the quality of the emission estimates.

  For instance, US Forest Service assessments only cover the parts of the State that the US Forest Service defines as forest, which represented 27% of the total State land area in

1997. Between the dates of the two most recent forest inventories, 1987 and 1997, the Forest Service changed its technical definition of forestland from minimum of 10% canopy cover to a minimum 5% cover. As a result, later years in the inventory period report increased carbon stocks due to this definitional change.[12] According the US Forest Service contacts, there is no ability on their part to normalize the forested acreage to a single definition (either 5% or 10%). However, the overall impact of the change in forest definition is expected to be small in comparison to other forest carbon modeling issues, including a lack of carbon measurements in pinyon/juniper systems (an important land cover type in NM).

To the extent that rangelands may sequester or emit carbon, while small on a per acre basis, they may be quite significant at the State level.[13] This is due to the large amount of rangeland cover present in NM. The current inventory does not include rangeland carbon sequestration estimates. Additional research in this area is recommended.

Another data limitation arises from the lack of inventory data since 1997. Due to funding constraints in New Mexico, US Forest Service data from the Forest Inventory Analysis (FIA) are not available from 1997 onward. As a result, biomass reductions from wildfires and forest health problems, or other carbon stock changes since that time, are not reflected in the estimates provided here. These changes need to be clarified to provide accurate forest carbon projections. For the time being, forest carbon projections are based solely on a linear extrapolation of the 1987-1997 period for which data are available, and do not factor in the effects of potential future changes in forest health, productivity and use.

- **Black carbon and other aerosol emissions.** Emissions of aerosols, particularly black carbon from fossil fuel and biomass combustion, could have potential significant impacts in terms of radiative forcing (i.e. climate impacts). Methodologies for conversion of black carbon mass estimates and projections to global warming potential involve significant uncertainty at present. If requested, CCS can prepare an inventory of black carbon emissions (both mass based and in CO2 equivalents).

[12] We hope to correct changes attributable to definition changes in an revised inventory, but cannot estimate the effect of this change yet. This definitional issue relates to the large amount of rangeland in the state that is not covered by a carbon flux inventory unless it meets minimum forestland cover requirements.
[13] However, the carbon cycle for rangelands is not well understood, and has not been included in current surveys.

Table 4. Simplified Calculation of Consumption-Basis Emissions for Electricity and Fossil Fuel Production

	1990	2000	2010	2020	units
Electricity					
Electricity Produced (net of RPS)	29	34	37	44	TWh
In-State Electricity Needs (net of RPS)	15	20	24	30	TWh
in-state share	*54%*	*59%*	*64%*	*69%*	
Electricity Production Emissions	29	33	33	38	MMtCO2e
Consumption-Basis Emissions	16	20	21	26	MMtCO2e
Natural Gas					
Natural Gas Produced*	965	1695	1604	1604	BCF
In-State Gas Requirements*	239	265	269	297	BCF
in-state share	*25%*	*16%*	*17%*	*19%*	
Natural Gas Industry Emissions	13	17	17	18	MMtCO2e
Consumption-Basis Emissions	3.1	2.7	2.9	3.3	MMtCO2e
Oil					
Oil Produced	52	69	64	64	Million Barrels
In-State Oil Requirements	41	47	60	73	Million Barrels
in-state share	*79%*	*69%*	*93%*	*114%*	
Oil Production Emissions	0.7	0.7	0.7	0.7	MMtCO2e
Consumption-Basis Emissions	0.5	0.5	0.6	0.8	MMtCO2e
Oil Refined	38	35	32	32	Million Barrels
In-State Oil Requirements	41	47	60	73	Million Barrels
in-state share	*106%*	*137%*	*185%*	*226%*	
Oil Refinery Emissions	1.6	1.6	1.6	1.6	MMtCO2e
Consumption-Basis Emissions	1.7	2.2	3.0	3.6	MMtCO2e
Coal					
Coal Produced	24	27	26	26	million short tons
Coal Consumed	15	17	18	20	million short tons
in-state share of coal consumption	*62%*	*61%*	*67%*	*76%*	
in-state share of elec consumption	*54%*	*59%*	*64%*	*69%*	
Coal Mining Emissions	0.2	0.2	0.7	0.7	MMtCO2e
Consumption-Basis Emissions	0.1	0.1	0.3	0.4	MMtCO2e

* Note that for consistency with natural gas consumption estimates, historical data for natural gas production shown are taken from the same source (US Energy Information Agency, marketed gas production). These numbers differ slightly from data compiled by the New Mexico EMNRD.

Table 5. Reference Case, Production-Based GHG Emissions, Detailed Results

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Electricity Production	**29.5**	**33.2**	**33.3**	**38.1**	
Coal	28.0	30.7	30.4	34.5	See electric sector assumptions in appendix
Natural Gas	1.4	2.5	2.9	3.5	
Oil	0.0	0.0	0.0	0.0	
Res/Comm/Non-Fossil Ind (RCI)	**7.0**	**7.3**	**8.5**	**9.9**	
Coal	0.1	0.2	0.2	0.2	Based on USDOE regional projections
Natural Gas	3.8	4.6	4.5	5.4	Based on USDOE regional projections
Oil	3.1	2.5	3.8	4.3	Based on USDOE regional projections
Wood (CH4 and N2O)	0.0	0.0	0.0	0.0	Assumes (for now) no change after 2003
Transportation	**11.0**	**14.2**	**17.6**	**22.3**	
On-road Gasoline	7.2	8.7	10.2	12.2	VMT from NMDOT, constant energy/VMT
On-road Diesel	2.5	4.2	5.6	7.9	VMT from NMDOT, constant energy/VMT
Natural Gas, LPG, Other	0.1	0.1	0.1	0.1	Based on USDOE regional projections
Jet Fuel and Aviation Gasoline	1.2	1.2	1.6	2.0	Based on USDOE regional projections
Fossil Fuel Industry	**15.2**	**19.5**	**20.3**	**20.7**	
Natural Gas Industry	12.7	17.0	17.3	17.7	Assumes no change in state gas production
Oil Industry	2.3	2.3	2.3	2.3	Assumes no change in state oil production
Coal Mining (Methane)	0.2	0.2	0.7	0.7	Assumes (for now) no change after 2003
Industrial Processes	**0.5**	**1.5**	**2.0**	**2.8**	
ODS Substitutes	0.0	0.5	1.3	2.3	Based on national projections (State Dept.)
PFCs in Semi-conductor Ind.	0.1	0.5	0.2	0.1	Based on national projections (USEPA)
SF6 from Electric Utilities	0.2	0.1	0.1	0.0	Based on national projections (USEPA)
Cement & Other Industry	0.2	0.4	0.4	0.4	Assumes (for now) no change after 2003
Carbon Dioxide Consumption					not yet estimated
Waste Management	**0.8**	**1.2**	**1.4**	**1.2**	
Solid Waste Management	0.6	1.0	1.1	0.9	Based on national projections (State Dept.)
Wastewater Management	0.2	0.2	0.3	0.3	Increases with state population
Agriculture	**4.5**	**6.0**	**6.4**	**6.7**	
Manure Mgmt & Enteric Ferment. (CH4)	2.3	3.5	4.1	4.4	Dairy emissions grow with population
Agricultural Soils (N2O)	2.2	2.4	2.3	2.3	No changes projected
Total Gross Emissions	**68.5**	**82.9**	**89.4**	**101.7**	
Forestry and Land Use	**-20.9**	**-20.9**	**-20.9**	**-20.9**	Awaiting further analysis
Net Emissions (incl. forestry)	**47.6**	**62.0**	**68.5**	**80.8**	

2. Approach

The principal goal of the inventory and reference case projections is to provide the State, stakeholders and technical work groups with a general understanding of New Mexico's historical, current and projected (expected) greenhouse gas emissions. Over the coming months, we will work with stakeholders and working groups to augment, refine and disaggregate these estimates.

2.1 General Principles and Guidelines

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

- **Transparency:** We report data sources, methods, and key assumptions to provide open review and opportunities for additional revisions later based on stakeholder and technical work group input.

- **Consistency:** To the extent possible, the inventory and projections are designed to be externally consistent with current or likely future systems for state and national GHG emission reporting. We have used USEPA tools for state inventories and projections as a starting point. These initial estimates were then augmented to conform to local data and conditions, as informed by New Mexico-specific sources and experts.

- **Comprehensive Coverage of Gases, Sectors, State Activities, and Time Periods.** This analysis aims to comprehensively cover GHG emissions associated with activities in New Mexico. It covers all six greenhouse gases covered by US and other national inventories: carbon dioxide, (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). Black carbon, organic carbon, and other potential GHG emission sources will be considered as data and methods allow.

- **Priority of Significant Emissions Sources:** In general, activities with relatively small emissions levels may not be reported in the same level of detail as other activities.

- **Priority of Existing State and Local Data Sources:** In gathering data and in cases where data sources may conflict, we place highest priority on local and state data and analyses, followed by regional sources, with national data used as defaults where necessary.

- **Presentation of Production-Based and Consumption-Based Emissions Estimates:** For all sources, we present emissions produced by in-state activities, which are referred to here as production-based emissions. For electricity, oil, and natural gas, which are produced in amounts well in excess of New Mexico requirements, we also estimate consumption-based emissions, i.e. the emissions reasonably attributable to the consumption of these products by consumers in New Mexico.

For electricity, consumption-based accounting, in principle, should reflect an understanding of the electricity sources used by New Mexico utilities to meet consumer demands. For this draft inventory, we take a simpler approach, estimating consumption-based emissions by multiplying total production-based emissions (from fuel combustion at all in-state power plants) times the fraction of total electricity produced (MWh) that would be needed to meet in-state electricity demands.

For fossil fuels, we first estimate (production-based) emissions related to extraction, refining, and transmission activities in the State. Similar to the electricity approach, we then estimate consumption-based emissions, by multiplying total production-based emissions times the fraction of total natural gas (or oil) produced (BTUs) that would be needed to meet in-state natural gas (or oil) demands.

2.2 General Methodology

We prepared this analysis in close consultation with New Mexico agencies, in particular, the Department of Environment (NMED) staff. The overall goal of this effort is to provide simple and straightforward estimates, with an emphasis on robustness and transparency. As a result, we rely on straightforward spreadsheet analysis rather than detailed modeling.

In most cases, we follow the same approach to emissions accounting used by the US EPA in its national GHG emissions inventory[14] and its guidelines for states.[15] These inventory guidelines were developed based on the guidelines from the Intergovernmental Panel on Climate Change, the international organization responsible for developing coordinated methods for national greenhouse gas inventories.[16] The inventory methods provide flexibility to account for local conditions.

The electricity and fossil fuel sectors are the areas in which we expand the US EPA inventory approach, by looking at consumption-based in addition to production-based emissions, as described above. We encourage New Mexico stakeholders to closely consider the question of whether and how to count GHG emissions from exports of electricity and fossil fuels produced in the State with respect to setting and tracking emissions. Stakeholders may also want to consider strategies that work together with neighboring states to reduce overall GHG emissions. A number of other accounting questions also need to be resolved, such as the treatment of transportation fuels used out of state and for international travel.

[14] US EPA, Feb 2005. *Draft Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003. http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html*.
[15] http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateInventoryGuidance.html
[16] http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm

Table 6. Key Sources for Data, Inventory Methods and Projection Growth Rates

Source	Information provided	Use of Information in this Analysis
US EPA State Greenhouse Gas Inventory Tool (SGIT)	EPA SGIT is a collection of linked spreadsheets designed to help users develop state GHG inventories. EPA SGIT contains default data for each state for most of the information required for an inventory.	Where not indicated otherwise, SGIT is used to calculate emissions from industrial processes, agriculture and forestry, and waste. We use SGIT emission factors (CO2, CH4 and N2O per BTU consumed) to calculate energy use emissions.[17]
US DOE Energy Information Administration (EIA) State Energy Data System (SEDS)	EIA SEDS source provides energy use data in each state, annually to 2002.	EIA SEDS is the source for all energy use data except on-road gasoline and diesel consumption. Emission factors from EPA SGIT are used to calculate energy-related emissions.
US DOE Energy Information Administration Annual Energy Outlook 2005 (AEO2005)	EIA AEO2005 projects energy supply and demand for the US from 2005 to 2025. Energy consumption is estimated on a regional basis. New Mexico is included in the Mountain Census region (AZ, CO, ID, MT, NM, NV, UT, and WY)	EIA AEO2005 is used to project changes in per capita (residential), per employee (commercial/industrial). (See Table 3)
New Mexico Department of Transportation (NMDOT)	NMDOT reports on-road gasoline and diesel consumption based on calculations from tax revenue.	NMDOT provides data for gasoline and diesel consumption.
NMDOT's New Mexico 2025 Statewide Multimodal Transportation Plan	The New Mexico 2025 analysis projects transportation demand.	This report is the source vehicle mileage growth rates in the transportation sector.

[17] We did not use the EPA SGIT tool directly to calculate emissions from energy use because the data in the tool has not been updated to the most recent energy consumption data. By calculating GHG emissions directly from energy use multiplied by the emissions factors from SGIT, we are able to use locally sourced energy data, such as NMDOT gasoline and diesel sales data.

Appendix A. Electricity Use and Supply[18]

New Mexico is an important supplier of electricity to the Western US. The State's power plants have historically produced more electricity than consumed in the State, and have exported significant amounts of electricity to Arizona, California, and other Western states. In 2000, for instance, New Mexico power plants produced 36% more electricity than needed for in-state use.[19] The New Mexico electricity sector is also dominated by coal, which accounts for nearly 90% of all electricity generated in recent years. Coal-fired power plants produce as much as twice the CO2 emissions per kilowatt-hour of electricity as natural gas-fired power plants. As a result of these factors, New Mexico power plants are the largest source of GHG emissions in the State.

As noted earlier, one of the key questions for the State to consider is how to treat GHG emissions that are produced to serve needs outside the State. In other words, should the State consider the GHG emissions associated with the State's electricity consumption or its electricity production, or some combination of the two? Since this question still needs to be resolved, this section examines electricity-related emissions from both a production and consumption basis.

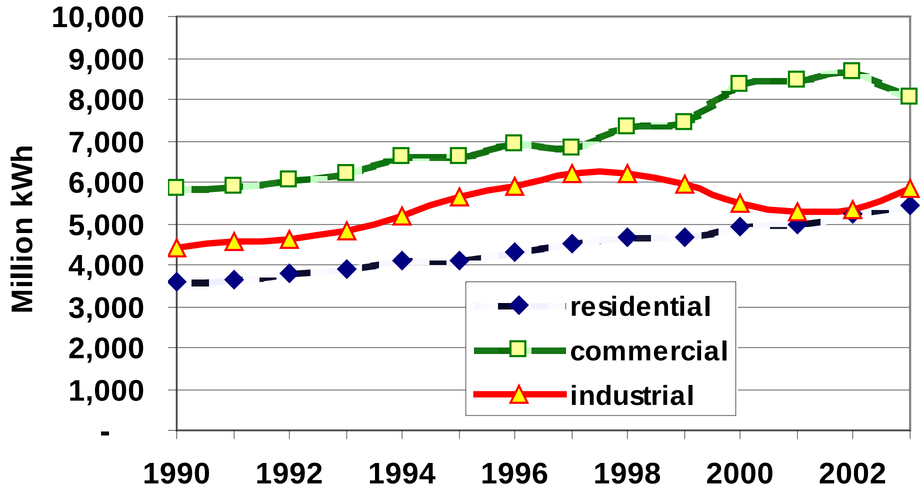
This appendix describes New Mexico's electric sector in terms of consumption and production, including the assumptions used to develop the reference case projections. It then describes New Mexico's electricity trade and potential approaches for allocating GHG emissions for the purpose of determining the State's inventory and reference case. Finally, key assumptions and results are summarized.

Electricity Consumption

At about 10,000 kWh/capita (2003 data), New Mexico has relatively low electricity consumption per capita. By way of comparison, the per capita consumption for the US is 12,000 kWh per year, with California averaging at 7,000 kWh, Arizona at 8,000 kWh, and Texas at 15,000 kWh. As shown in Figure 7, the commercial sector has the greatest electricity consumption in New Mexico, with strong growth from 1990, except for a slight decrease in 2003. The industrial sector grew strongly from 1990 to 1997 then dropped through 2001 with some increase in the last couple years.[20] The residential sector, has the lowest consumption among sectors, but is growing the most rapidly, averaging 3.3% annually from 1990 to 2003, compared with population growth of 1.7%.

[18] The Energy Supply Technical Working Group reviewed and accepted the assumptions and results shown in this section.
[19] EGRID2002 software (US EPA http://www.epa.gov/cleanenergy/egrid/whatis.htm)
[20] Electricity consumption figures here only include purchased electricity, and do not include electricity generated and consumed internally by specific industries, such as mining.

Figure 8. Electricity Consumption by Sector, 1990-2003



The States' four investor-owned utilities serve approximately 70% of the customers, and 70% of load, as illustrated in Table 7. The State's 20 rural electric cooperatives serve 22% of customers, although they service about 85% of the State's land area. There are seven municipal electric utilities serving the remaining eight percent of the State's electric customers. (EMNRD, 2003)

Table 7. Retail Electricity Sales by New Mexico Utilities (2002)

	2002 GWh
Top 5 Utilities, ranked by retail sales	
Public Service Company of New Mexico	7,407
Southwestern Public Service	3,443
El Paso Electric Company	1,355
City of Farmington	1,043
Texas - New Mexico Power Company	1,018
Total of above utilities	14,266
Total, all New Mexico	19,207

Source: EIA state electricity profiles

Overall, total electricity consumption grew at an average annual rate of 2.6% from 1990 to 2003, about half the rate of gross state product growth (5% per year).[21] For initial projections, future electricity consumption is projected to grow at a rate of 2.5% per year through 2020, compared with expected population growth of 1.3% per year.[22]

[21] Gross State Product growth from Bureau of Economic Analysis, http://www.bea.doc.gov/bea/regional/gsp/default.cfm
[22] This growth rate was suggested by EMNRD staff, based on growth rates discussed by electricity providers of 1.5%-2% per year for the utilities and 3.6% per year from co-operatives.

Electricity Generation –New Mexico's Power Plants

As mentioned above and displayed in Figure 8 below, coal figures prominently in electricity generation and GHG emissions from power plants in New Mexico. Table 8, which reports the emissions from the largest plants from 1995 to 2003, shows that two plants Four Corners and San Juan account for the vast majority of emissions. As explained further in the electricity trade section below, both of these plants are partly owned by utilities outside of New Mexico (only 14% of Four Corners and about 54% of San Juan capacity are owned by New Mexico utilities). While some of the electricity generated by these plants serves needs for New Mexico residents and businesses, much is used to serve those outside the State. Conversely, New Mexico utilities own shares of plants in other states.[23]

Figure 9. Electricity Generation and CO2 Emissions from New Mexico Power Plants, 2002

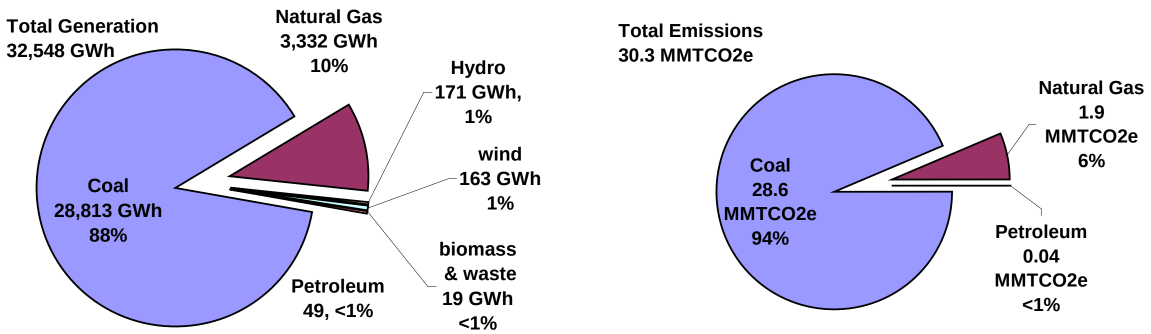


Table 8. CO2 Emissions from Individual New Mexico Power Plants, 1995-2003

(Million Metric Tons CO2e)	1995	1996	1997	1998	1999	2000	2001	2002	2003
Four Corners Steam	15.7	14.5	14.5	15.3	15.9	15.4	15.6	13.5	14.8
San Juan	11.0	12.7	13.2	13.0	12.5	13.2	12.5	13.1	11.1
Prewitt Escalante	1.2	1.8	2.1	1.5	2.1	2.0	1.7	1.6	1.7
Rio Grande	0.6	0.5	0.5	0.6	0.5	0.6	0.5	0.5	0.5
Maddox	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.3	0.3
Other units	0.9	1.0	1.3	1.4	1.5	1.6	1.7	1.2	1.2
Total	**29.6**	**30.8**	**31.9**	**32.2**	**32.7**	**33.1**	**32.4**	**30.2**	**29.5**

Source: USEPA Clean Air Markets database for named plants (http://cfpub.epa.gov/index.cfm). Other units calculated from fuel use data provided by US DOE EIA.

Future Generation and Emissions

[23] Emissions from the 5 largest power plants were obtained from the EPA Clean Air Markets database, http://cfpub.epa.gov/gdm/index.cfm. Since data from the EPA Clean Air Markets Division do not include plants under 25MW, supplemental data were required for a complete emissions estimate. Emissions for all remaining power plants were calculated by using the energy consumption for the remaining plants multiplied by EPA emissions factors by fuel, accounting for combustion efficiency and changes in average carbon content of coal over time.

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

Table 9 lists the characteristics of recent and several proposed plants. As shown, there are proposals on the drawing boards for over 2500 MW of new power plants, most of them coal-based. If built and fully operated, these power plants could produce over 15 $MMtCO_2$ in GHG emissions. However, the future mix of plants in New Mexico remains uncertain as the trends in type of new builds are influenced by many factors:

- The most recent fossil-fuel plants have been natural gas-fired, however there are concerns that natural gas prices may increase over the next decade, which could cause a trend towards more coal-dominated.

- Several coal plants have been proposed – taking advantage of the current price advantage for coal plus support from federal government for clean coal – but construction could be limited by air quality requirements.

- Some proposed plants have applied for permits, including natural gas and biomass facilities. Permitted plants are not always built. Actual implementation depends on market conditions, adequate financing, and other factors. Permits are only valid for specified timeframe; if construction does not begin during this period, the developer must resubmit the application, and it may or may not be granted again depending on emerging conditions.

- In the last few years several wind plants have been developed and others have been proposed. These developments reflect the declining cost of wind plants, federal and state incentives (production tax credit and renewable portfolio standard), and increased customer demand for “green” electricity.

Table 9. Recently Constructed, Approved and Proposed Plants in New Mexico

	Plant Name	Fuel	Status	Capacity MW	Expected generation GWh	Annual Emissions MMTCO2e	Notes
Wind Plants	New Mexico Wind Energy Center	wind	On-line Oct 2003	200	594	0	used by PNM to meet RPS
	Caprock Cielo/Xcel	wind	80 MW on-line in 2004/2005	80	299	0	Used by Southwestern to meet RPS and customer green electricity choice
	San Juan Mesa	wind	expected on-line by December 2005	120	368	0	Used by Southwestern to meet RPS and customer green electricity choice
New plants	Afton[1]	Natural gas	On-line 2002	135	14	0.01	Designed by PNM for Western wholesale market
	Bluffview[2]	Natural gas	On-line 2005	60	447	0.16	City of Farmington
	Lordsburg[1]	Natural gas	On-line 2002	80	65	0.04	Designed by PNM for peaking power
	Luna[2]	Natural gas	under-construction 2006	570	4,244	1.50	Recently purchased by consortium including PNM
	Pyramid[2]	Natural gas	On-line 2003	160	1,191	0.42	Pyramid assists in serving Tri-State's southern system loads and provides backup generation.
Proposed plants	Mustang[2]	coal	An air quality permit application accepted.	300	2,234	1.85	
	Desert Rock Energy Project[2]	coal		1500	11,169	9.23	Sithe Global Power's has proposed a 1500 MW of new coal-fired electrical production to be located on Navajo lands in the 4 Corners
	BHP Billiton[2]	coal		550	4,095	3.38	BHP Billiton's subsidiary Chaco Valley Energy submitted a permit application for a power plant that would operate if the Desert Rock proposal (see above) does not go through.
	Valencia Energy[2]	Natural gas		337	2,509	0.89	This project has received permits but not broken ground
	Northeast New Mexico Biomass	biomass		35	261		

Sources: New Mexico Environment, Air Quality website, discussions with Ted Schooley and Sam Speaker (NMED), Donald Groves (PNM), City of Farmington utility, also Western Resource Advocates website (http://westernresources.org/energy/newmcoal.html)

Notes:

Generation for wind plants is based on information from utility websites. Generation for new fossil fuel plants is estimated using an 85% capacity factor.

1. Emissions are estimated by average 2003 and preliminary 2004 data from USEPA's Clean Air Markets division.
2. Emissions are based on USDOE Annual Energy Outlook assumptions

Given these uncertainties, and a diversity of perspectives by actors within the electricity sector, it is particularly challenging to develop a "reference case" projection for the most likely development of New Mexico's electricity sector. Therefore, to develop an initial projection, simple assumptions were made, relying to the extent possible on widely-reviewed modeling assessments. The reference case projections assume:

- Total generation in New Mexico grows at the regional growth rates forecast by the National Energy Modeling System (NEMS) developed by the US Energy Information Administration for projecting US energy supply and demand to 2025 in the US DOE's Annual Energy Outlook 2005.

- Generation from existing coal plants is based on Western Regional Air Partnership (WRAP) analyses[24]; generation from all other plants is assumed to remain at 2003 levels. Existing plants include those on-line or expected on-line by the end of 2005.

- Generation from new power plants provides the remainder of this growth. New Mexico utilities are expected to build renewables as needed to comply with the State *Renewable Portfolio Standard; it* is assumed that wind generation will dominate these renewable power additions, per utility plans.[25] The remainder of generation growth is expected to be supplied a mix of 80% coal and 20% natural gas; this assumptions is based on review of studies noted in Table 10 below.

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Electricity Trade and Allocation of GHG emissions

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

In 2003, electricity consumption in New Mexico was 19.3 TWh while electricity generation was 32.5 TWh. Also, as mentioned above, New Mexico utilities own less than 32% of the two largest plants in the State (San Juan and Four Corners). Thus a significant portion of the electricity generated and economic benefits may serve consumers and investors in other states. Similarly, all of the largest utilities (except City of Farmington) own shares in plants outside of the State (e.g. Public Service Company of New Mexico (PNM) owns 10% of Palo Verde nuclear plant).

Since almost all states are part of regional trading grids, many states that have developed GHG inventories have grappled with this problem and several approaches have been developed to allocate GHG emissions from the electric sector to individual states for inventories.
In many ways the simplest approach is *production-based* – emissions from power plants within the State are included in the state's inventory. The data for this estimate are publicly available and unambiguous. However, this approach is problematic for states that import or export

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[24] From WRAP Market Trading Forum, Grand Canyon Visibility Transport Commission, Emission Inventory Reconciliation v4_01 spreadsheet
http://www.wrapair.org/forums/mtf/documents/group_reports/TechSupp/SO2Tech.htm

[25] http://www.pnm.com/regulatory/pdf_electricity/renewable_stip_05.pdf
http://www.epelectric.com/internetsite/renewable.nsf/by+subject/Transitional
+Procurement+Plan+Application/$file/Procurement+Plan+Application.pdf?OpenElement
http://www.xcelenergy.com/docs/corpcomm/NM-PortfolioReportProcurementPlan.pdf

significant amounts of electricity. Because of the State's large exports, under a production-based approach New Mexico residents would be taking responsibility for emissions that they have limited ability to mitigate and that provide limited benefit to the State.

An alternative is to estimate *consumption-based* or *load-based* GHG emissions, corresponding to the emissions associated with electricity consumed in the State. The load-based approach is currently being considered by states that import significant amounts of electricity, such as California, Oregon, and Washington.[26] By accounting for emissions from imported electricity, states can account for increases or decreases in fossil-fuel consumed in power plants outside of the State, due to demand growth, efficiency programs, and other actions in the State. The difficulty with this approach is properly accounting for the emissions from imports and exports. Since the electricity flowing in or out of New Mexico is a mix of all plants generating on the inter-connected grid, it is impossible to physically track the electrons.

The approach taken in this initial inventory is a simplification of the consumption-based approach. This approach, which one could term "*Net-Consumption-based*", estimates consumption-based emissions as in-state (production-based) emissions times the ratio of total in-state electricity consumption to in-state generation (net of losses). For example, in 2003, New Mexico residents and business consumed 66% (19.3 TWh) of total in-state generation (32.5 TWh) net of transmission and distribution losses (10%).

This method does not account for differences in the type of electricity that is imported or exported from the State, and as such, it provides a simple method for reflecting the emissions impacts of electricity consumption in the State. More sophisticated methods – e.g. based on individual utility information on resources used to meet loads – can be considered for further improvements to this approach.

Summary of Assumptions and Reference Case Projections

As noted, projecting generation sources, sales, and emissions for the electric sector out to 2020 requires a number of key assumptions, including economic and demographic activity, changes in electricity-using technologies, regional markets for electricity (and competitiveness of various technologies and locations), access to transmission and distribution, the retirement of existing generation plants, the response to changing fuel prices, and the fuel/technology mix of new generation plants. The key assumptions described above are summarized in Table 10.

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

Table 10. Key Assumptions and Methods for Electricity Projections

Electricity sales	2.5% annual growth rate, based on input from EMNRD
Electricity generation	2.5% annual growth is assumed to match sales growth from 2004-2010. 2% annual growth is assumed from 2011 to2020, based on regional growth in EIA AEO2005 (AZ, NM and southern NV)
Transmission and Distribution losses	10% losses are assumed, based on average statewide losses, 1994-2000, (data from EPA Emission & Generation Resource Integrated Database[27])
New Renewable Generation Sources	Public Service of New Mexico and Southwestern Public Service and El Paso Electric Company follow procurement plans filed in 2004 (resulting in new wind plants that will exceed the RPS requirements until 2010). After 2010, new renewable plant builds are assumed to sufficient to meet but not exceed RPS. For other utilities, no additional new renewables are assumed.
New Non-Renewable Generation Sources (2004-2010)	From 2006-2010, the assumed mix is 20% coal and 80% natural gas (MWh basis), based on the dominance of natural gas among plants currently under construction.
New Non-Renewable Generation Sources (2011-2020)	For 2011 to 2020, the assumed mix is 80% coal and 20% natural gas (MWh basis), based on a review of studies including EIA AEO2005, ICF/WRAP 2002, and others.[28]
Heat Rates	The assumed heat rates for new gas and coal generation are 7000 Btu/kWh and 9000 Btu/kWh, respectively, based on estimates used in similar analyses.[29]
Operation of Existing Facilities	Current sources of coal-based electricity generation increase output according to analysis completed for the WRAP.[30]

Figure 9 shows historical sources of electricity generation in the State by fuel source, along with projections to the year 2020 based on the assumptions described above. Natural gas generation has grown considerably during the past decade, while coal and hydro generation have stayed relatively constant. The first major wind project, New Mexico Wind Energy Center, came on-line in 2003 and wind generation is expected to grow in the next couple years as utilities complete plants built to meet renewable portfolio standard. Based on the above assumptions for new generation, natural gas continues to dominate new generation through 2010, at which point coal assumes an increasing market share, reflecting assumptions that natural gas prices will continue to rise.

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

[28] Western Resource Advocates, 2004. *A Balanced Energy Plan for the Interior West.* http://www.westernresourceadvocates.org/energy/bep.html and ICF 2002. *Economic Assessment of Implementing the 10/20 Goals and Energy Efficiency Recommendations* (prepared for Western Regional Air Partnership).

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

[30] See emissions reconciliation documentation for 2000/2001 at http://www.wrapair.org/forums/ mtf/documents/group_reports/TechSupp/SO2Tech.htm. The results of this analysis are referenced in subsequent WRAP analyses, including *An Assessment of Critical Mass for the Regional SO_2 Trading Program* (ICF 2002)

Figure 10. Electricity Generated By New Mexico Power Plants, 1990-2020

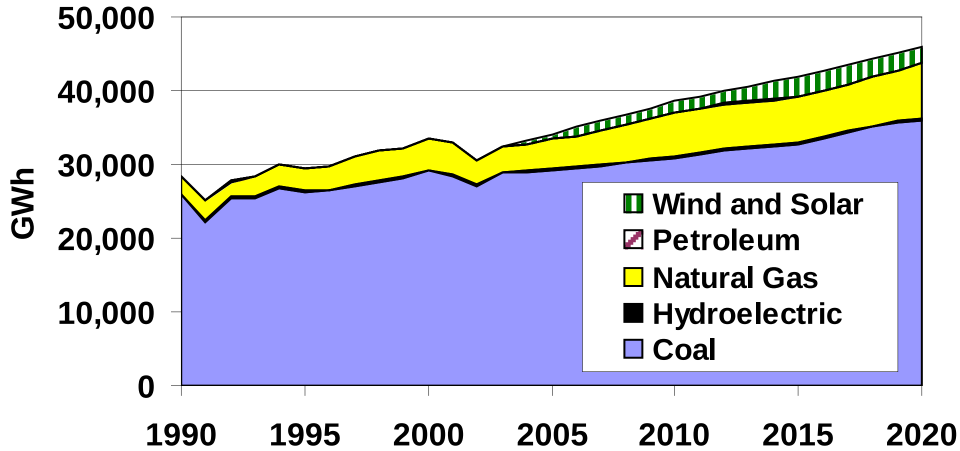


Figure 10 illustrates the GHG emissions associated with the mix of electricity generation shown in Figure 9. From 2005 to 2020, the emission from New Mexico electricity generation are projected to grow at 1.3% per year, slower than the 2.5% growth in electricity generation, due to increased natural gas generation and assumed increases in energy efficiency of new coal plants that are built after 2010 (compared to efficiency of existing units today). As a result, the emission intensity (emissions per MWh) of New Mexico electricity is expected to decline by about 10% (from 0.91 MTCO2/MWh in 2000 to 0.82 MTCO2/MWh in 2020).

Figure 11. CO_2 Emissions Associated with Electricity Production (Production-Basis), Includes Exports

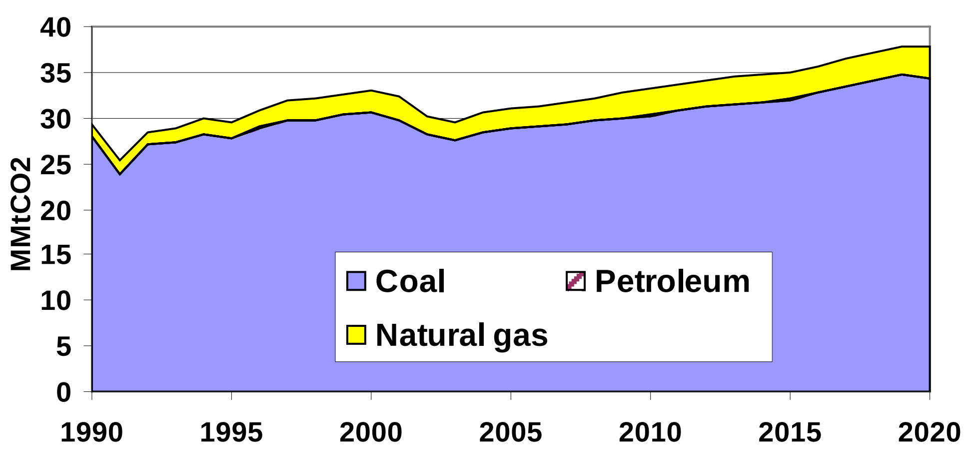
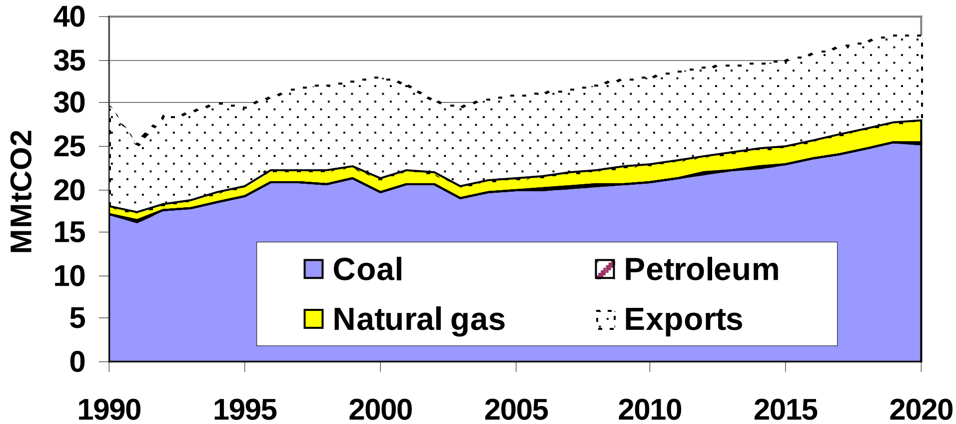


Figure 11 shows the "net-consumption-basis" emissions from 1990 to 2020. Total emissions match those shown in the previous "production-basis" chart; here, however, a significant fraction is attributed to net electricity exports as shown in the top area.

Figure 12. CO_2 Emissions Associated with Electricity Use (Consumption-Basis) and Exports



Key uncertainties and next steps

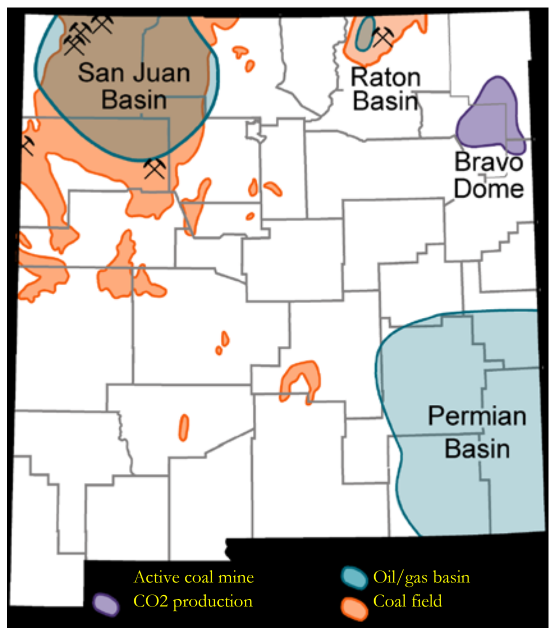
As noted above, these estimates are subject to a number of uncertainties. Perhaps the uncertainty with the most important implications for GHG emissions is the type, size, and number of power plants built in New Mexico between now and 2020. As noted above, there are also significant uncertainties associated with projecting electricity consumption in the State, as well as in the estimation of consumption-based electricity emissions (i.e. which electricity sources serve New Mexico loads). If a consumption-based emissions approach is adopted by the State, further analysis should be directed towards the resources that utilities use to meet New Mexico loads, and methods that can be reliably used to track them.

Appendix B. Fossil Fuel Industry Emissions[31]

The oil and gas industry has played an instrumental role in New Mexico's economy and livelihoods for more than 70 years. Oil and gas revenues currently provide about 20% New Mexico's General Fund -- down from historic highs of nearly 90% -- and the industry provides employment for about 10,000 New Mexicans.[32] The State currently ranks second in the nation in natural gas production and fifth in crude oil production.[33] It is also a leader in both the production and reserves of carbon dioxide, which is used largely for enhanced oil recovery.

Natural gas production is concentrated in the northwestern corner of the State (San Juan Basin), while oil production occurs predominantly in the southeast (Permian Basin). (See Figure 12) As of 2002, over 700 oil and gas industry-related companies operated in the State, working 21,771 oil wells, 23,261 gas wells, 456 CO_2 wells, 4,097 enhanced recovery injection wells and 597 salt water disposal wells.[34] In response to expectations of strong US natural gas demands and firm prices, it is expected that another nearly 10,000 gas wells may be drilled in the San Juan Basin in coming years.[35] In addition, there are over 4,500 inactive, non-plugged oil and gas wells that could potentially be returned to production.[36]

Figure 13. Fossil Fuel and CO2 Producing Regions of New Mexico



Source: **http://geoinfo.nmt.edu/resources/petroleum/**

While coalbed methane (CBM) supplies less than 10% of total US natural gas production, it accounts for nearly a third of New Mexico's natural gas production: 487 of the 1625 billion cubic feet (BCF) produced in 2002.[37] Coalbed methane is found throughout the Rocky Mountain Region, including the Raton and San Juan Basins that span both Colorado and New Mexico. The Fruitland Coal formation of the San Juan Basin is the largest CBM source in the US.

CBM production from the New Mexico portion of the San Juan Basin peaked in 1999 at over 610 Bcf (billion cubic feet), and has since dropped under 500 BCF annually since 2002. At the same time, increased drilling in response to expected high demand and prices for natural gas

[31] The Energy Supply Technical Working Group reviewed and accepted the assumptions and results shown in this section.
[32] EMNRD, 2003. *New Mexico's Natural Resources 2003* http://www.emnrd.state.nm.us/Mining/resrpt/default.htm
[33] US DOE Energy Information Agency website.
[34] ENMRD, 2003.
[35] Bureau of Land Management, 2003. Farmington Resource Management Plan with Record of Decision, December 2003. Farmington Field Office.
[36] EMNRD, 2003
[37] EMNRD, 2003 and data provided separately by the Oil Conservation Division.

could postpone further decreases in CBM production. Overall, future oil and gas production levels remain highly uncertain, dependent on prevailing oil and gas prices and the potential development of new reserves.

Oil and Gas Industry Emissions

The sheer number and wide diversity of oil and gas activities in New Mexico present a major challenge for greenhouse gas assessment. Emissions of carbon dioxide and methane occur at many stages of the production process (drilling, production, and processing/refining), and can be highly dependent upon local resource characteristics (pressure, depth, water content, etc.), technologies applied, and practices employed (such as well venting to unload liquids which may result in the release of billions of cubic feet of methane annually). With over 40,000 oil and gas wells in the State, three oil refineries, several gas processing plants, and tens of thousands of miles of gas pipelines in the State – and no regulatory requirements to track CO_2 or CH_4 emissions – there are significant uncertainties with respect to the State's GHG emissions from this sector.

At the same time, considerable research – sponsored by the American Petroleum Institute, the Gas Research Institute, US EPA, and others – has been directed towards developing relatively robust GHG emissions estimates at the national level. For the national GHG inventory, US EPA uses a combination of top-down and detailed bottom-up techniques to estimate national emissions of methane from the oil and gas industry (USEPA, 2005). As noted earlier, US EPA has also developed a tool (SGIT) that enables the development of state-level GHG estimates, whereby emissions-related activity levels (numbers of wells, and amount of oil and gas produced) can be multiplied by aggregate emission factors to yield rough estimates of total CH4 emissions. Furthermore, EIA provides estimates of fuel used in New Mexico for natural gas production, processing, and distribution, which enables the estimation of CO2 emissions.

These sources provide a starting point for analysis of New Mexico's oil and gas industry emissions. Additional data and insights have been solicited from industry sources, including the New Mexico Oil and Gas Association (NMOGA) and individual facility managers, US EPA staff, and State agency experts. These sources provided "ground truthing" on several aspects related to State emissions. For example:

- Oil refiners and NMED provided access to permit data that includes estimated fuel consumption. These sources suggest that refinery gas use is over twice the level suggested by EIA data.
- USEPA staff remarked that methane emissions from well venting activities in New Mexico, especially at low pressure CBM sites where the build up of liquids may require venting, appear to be quite significant, perhaps on the order of 40 BCF annually (1.6 million $MMtCO_2eq$).[38]

[38] Personal communication, Roger Fernandez. (It also appears that that some producers have been able modify practices to reduce well venting emissions by about 50%, suggesting a potentially significant source of emission reductions.) This is only one of several significant sources of methane emissions from gas production. The preferred USEPA (SGIT) approach for estimating natural gas production emissions, which involves multiplying national aggregate per well CH4 emissions by the number of New Mexico wells, yields total methane emissions

- NMOGA provided separate estimates for several emissions sources, including carbon dioxide emissions from gas well site equipment (gas combustion in engines, tank heaters, and field separators), and methane and carbon dioxide emissions from venting and flashing activities at field sites. While these data only cover gas production activities in the San Juan Basin, they suggest rates of field gas use (carbon dioxide) and methane emissions that are 50% to 70% higher than the above (EPA-based) estimates. We consider these rates below in a sensitivity analysis.
- Raw gas that emerges from gas and oil wells often contains "entrained" CO_2 in excess of pipeline specifications. This CO_2 is typically separated at gas processing plants and vented to the atmosphere (except in some other states, such as Wyoming and Texas, where it is compressed and transported for enhanced oil recovery).[39] In the case of New Mexico, the CO_2 concentrations of Fruitland CBM are known to be quite significant (currently around 18%), and these concentrations have been rising over time. Data provided by the Oil Conservation Division of EMNRD and NMOGA enable estimates of entrained CO_2 emissions. Though these estimates cover only Fruitland CBM, which accounts for less that a third of New Mexico gas production, it is thought that this is the most significant source of entrained CO2 in the State.
- CO_2 from enhanced oil recovery – In New Mexico, carbon dioxide is extracted from natural formations (Bravo Dome), piped to oil fields, and injected into wells in order to increase yields. Any release of this CO2 during the extraction, transmission, injection, or oil production processes would lead to net emissions to the atmosphere. At the national level, USEPA currently excludes any such emissions from the national inventory, since they are not well understood. In the case of New Mexico practices, NMED is currently looking into available information to assess where any estimates are possible.

Table 12 provides an overview of the methods used to estimate and project GHG emissions from the various oil and gas sector activities. As shown, a variety of methods were used, in general relying upon local data and guidance from industry and other experts wherever possible.

Several factors will drive future GHG emissions from New Mexico's oil and gas sector, among them:

- Future oil and gas production activity. This is perhaps the most important, yet most uncertain variable that will affect future GHG emissions. One assessment suggests that barring further discovery or development of new reserves, coalbed methane production will remain level for one or two more years, and then begin declining at rate of 13% annually as the fields are depleted.[40] Conventional gas production in the San Juan Basin, under this assessment, would remain flat through the end of the decade, and similarly

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estimates that are significantly less than the national average (per unit natural gas produced), which does not appear justified. Based on discussions with USEPA staff, it was felt that their alternative (SGIT) method – using the New Mexico production-weighted share of national natural gas production methane emissions – would be a better approach for developing initial methane emissions estimates.

[39] On a national level, the USEPA GHG inventory suggests that these entrained CO_2 emissions are quite significant (about 25 MMtCO2in 2002). However, USEPA is still working to systematically incorporate this emissions source into the national inventory, given concerns about double counting emissions in locations (outside New Mexico) where this CO_2 may be used for enhanced oil recovery.

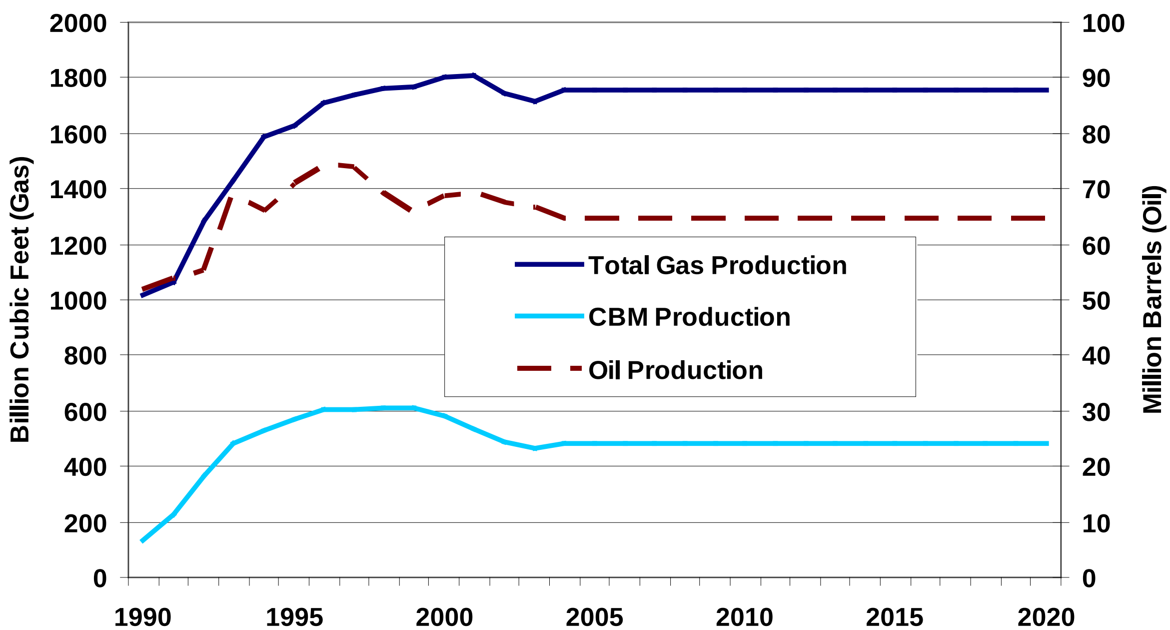
[40] Bernstein Research Call, May 27, 2005.

begin declining at 13% per year. (This assessment covered only the San Juan Basin)

Not surprisingly, there are many competing views on the future of oil and gas production, and prognostications of declining production have been made in the past. Total statewide natural gas production has been relatively steady from 1997 to 2004, varying by less than 6% over this 8-year time period. Thus another possible scenario is that additional reserves are found and exploited such that production remains constant through 2020. The Energy Supply Technical Working Group evaluated the differing views on future oil and gas production and came to the conclusion that the most likely was that emissions remain constant in the sector, and this assumption was used in preparing this inventory.

The implications of this assumption in terms of oil and gas production are depicted in Figure 13 below.

Figure 14. Future Oil and Gas Production



- Number of operating wells. As many of the oil and gas fields play out, more operating wells may be needed to maintain production levels. Some emissions, fugitive methane in particular, may depend on the number of operating wells as much as on total oil and gas production. The projected increase in the number of operating wells is based on the estimates contained in the BLM's Resource Management Plan for the San Juan Basin. Note that this estimate will likely need to be adjusted to correspond to the oil and gas production scenario chosen above.

- Changes in production, processing, and pipeline technologies and practices. In response to industry and USEPA emission reduction initiatives (e.g. GasStar), as well as technological advancements, progress has been made in lower GHG emissions per unit of oil and gas produced and delivered. Further improvements are likely, but have not been estimated for this initial analysis.

Key assumptions are noted in Table 11.

Table 11. Key Assumptions for the Oil and Gas Sector Projections

Parameter	Assumption
Natural Gas and Oil Production	Flat oil and gas production through 2020 See text for details
Oil Refinery Production	No changes in refinery activities (or emissions) are presently assumed.
GHG emissions per unit input/output	Potential emissions savings particularly for methane could be considerable, but are not considered here due to lack of information.

Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. This methane is typically referred to as "coal mine methane" in contrast coal bed methane, which is associated with coal seams (such as Fruitland) that are not expected to be mined.

Historical coal mine methane emissions were estimated using the EPA SGIT tool, which multiplies coal production times an average emission factor, depending on the mine type. Coal mine methane emissions are considerably higher, in general, per unit of coal produced, from underground mining than from surface mining.

As of 2003, six surface mines were operation in New Mexico. In 2001, underground operations commenced at the San Juan coal mine, and since then surface operations at one other mine (Ancho) has been significantly curtailed. The increasing share of underground coal in recent years has led to an increase in estimated coal mine methane emissions from about 0.2 MMtCO2e to 0.7 MMtCO2e.

Future coal mine methane emissions will depend on the extent to which operations continue to move underground (which could increase emissions significantly) and/or new coal mining operations change in response to demands from the power market. No effort has yet been made to estimate these potential changes.

Table 12. Emissions Sources and Estimation Methods for the Oil and Gas Sector

Activity	Emissions Source	Approach to Estimating Historical Emissions	Projection Approach
Natural Gas Drilling and Field Production	CO_2 from field use of natural gas	EIA data	Changes with number of operating wells. (CH_4 emissions savings due to further NG Star activity not considered).
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on total production). EPA staff separately estimate 40 BCF CH_4 (1.6 MMtCO2e) could result from well venting alone.	
Natural Gas Processing	CO_2 from fuel use in gas processing	EIA data	Changes with total statewide gas production or for the case of entrained CO2, with Fruitland gas production. CO_2 concentrations of Fruitland CBM are assumed to increase based on recent trends.
	CO_2 released fro entrained CO_2	Based on NMOGA estimates of CO2 concentration, and NM Oil Conservation Division estimates of gas production, for the Fruitland CBM field. No estimates made for other gas production sources.	
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on state vs. US production)	
Natural Gas Transmission and Distribution	CO_2 from fuel use (pumps, compressors)	EIA data	Distribution emissions grow with state gas consumption. No changes currently assumed for transmission-related emissions. Could decrease due to further NG Star activity.
	CH_4 from leaks, venting, upsets, etc.	NM share of transmission & distribution national emissions, based on NM share of national transmission line mileage (transmission) and natural gas consumption (distribution)	
Oil Production	CO_2 from fuel use	EIA data	Grows with state oil production.
	CH_4 from leaks, venting, upsets	SGIT tool.	
Oil Refining	CO_2 from on-site fuel use (refinery gas and natural gas)	Based on fuel use and capacity as reported to NMED in permit data. No annual variations considered.	Grows with oil refinery output.
	CH_4 from leaks and combustion	SGIT tool (included with production above)	
Oil Transport	CO_2 from field use of natural gas	No estimates available	Grows with state oil production.
	CH_4 from combustion	SGIT tool (included with production above)	
Carbon Dioxide Production	CO_2: Fugitive Losses	Not included/no information available.	n/a
	CO_2: Enhanced Oil Recovery	Not yet estimated	n/a
	CO_2: Other uses (shown with industrial process emissions)	Production data. Assume only 1% is for non-oil recovery applications (EMNRD as cited in USEPA, 2005).	No changes assumed.

Overall Results

The resulting emissions estimates for the fossil fuel industry are shown in Table 13 below. As shown, total fossil fuel industry emissions are quite significant, increasing from 15 to nearly 20 MMtCO2e during the 1990s, largely as the result of increased gas production, and in particular of coalbed methane, which led to an increase in the release of entrained carbon dioxide by over 4 MMtCO2. As shown in this table, GHG emissions would likely remain near 2000 levels through 2020, assuming no new and major efforts to reduce fuel use and/or emissions.

Table 13. Emissions Estimates for the Oil and Gas Sector, by Source and Gas, 1990-2020 (Scenario A)

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Fossil Fuel Industry	**15.2**	**19.5**	**20.3**	**20.7**	
Natural Gas Industry	**12.7**	**17.0**	**17.3**	**17.7**	
Production					
Fuel Use (CO2)	1.8	2.0	1.9	1.9	grows with gas production
Methane Emissions (CH4)	1.9	3.4	3.7	3.7	grows with gas production
Processing					
Fuel Use (CO2)	1.9	2.1	2.0	2.0	grows with gas production
Methane Emissions (CH4)	0.8	0.8	0.9	0.9	grows with gas production
Entrained Gas (CO2)	0.8	5.0	5.2	5.6	grows with CBM prod & CO2 concentration
Transmission					
Fuel Use (CO2)	4.2	2.3	2.3	2.3	no change assumed from 2003 on
Methane Emissions (CH4)	1.0	0.9	0.9	0.9	no change assumed from 2003 on
Distribution					
Fuel Use (CO2)					included in transmission (above)
Methane Emissions (CH4)	0.4	0.4	0.3	0.4	grows with gas consumption
Oil Industry	**2.3**	**2.3**	**2.3**	**2.3**	
Production					
Fuel Use (CO2)					included in industrial oil use (above)
Methane Emissions (CH4)	0.7	0.7	0.7	0.7	grows with oil production
Refineries					
Fuel Use (CO2)	1.6	1.6	1.6	1.6	assumes no major changes
Methane Emissions (CH4)					included in oil production (above)
Coal Mining (Methane)	**0.2**	**0.2**	**0.7**	**0.7**	no change assumed from 2003 on

These results as noted earlier are highly sensitive to several assumptions, most notably emissions rates associated with natural gas production activities and future trajectories for oil and gas production. If the emissions rates estimated by NMOGA for oil and gas activities in the San Juan Basin (in 2002) are assumed to apply for all gas production activities in the State, then natural gas production emissions would be about 3 to 4 MMtCO2e higher than shown in Table 13.[41]

[41] Estimated emissions for 2002 (not shown) would be 2.5 MMtCO2e higher for methane, and 0.9 MMtCO2e higher for carbon dioxide.

(See Section 1 for a discussion of consumption-based emissions for fossil fuel production activities)

Major Uncertainties and Other Issues

The uncertainties in emissions for the fossil fuel industry are perhaps more significant than in any sector other than forestry. Methane emissions and entrained carbon dioxide emissions in gas production and processing represent over half of these emissions. However, these emissions are not directly monitored and can only be estimated using industry assumptions. Field practices can vary considerably, e.g. with respect to flashing and venting, depending on the operator and the resource involved, and there is no monitoring of these practices. There are also significant with respect to methane emissions in transmission and distribution systems, since there is no systematic monitoring and emissions from venting and leaks can vary considerably from site to site.

In addition, significant uncertainties remain with respect to:

- The quality of historical data on field, processing, and pipeline use of natural gas.
- CO2 emissions from enhanced oil recovery, which have not been estimated.
- Refinery fuel use. EIA indicates less than half the refinery fuel use as indicated by refinery permit data.
- Coal mine methane. More accurate estimates would require mine-specific measurements.

Description of Sources of Methane emissions in the Oil and Gas Industry
Excerpted from the US national GHG inventory (USEPA, 2005)

Petroleum Systems

- *Production Field Operations*. Production field operations account for over 95 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 83 percent of the emissions from the production sector, fugitive emissions account for six percent, combustion emissions ten percent, and process upset emissions barely one percent. The most dominant sources of vented emissions are field storage tanks, natural gas-powered pneumatic devices (low bleed, high bleed, and chemical injection pumps). These four sources alone emit 79 percent of the production field operations emissions. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure.
- *Crude Oil Transportation.* Crude oil transportation activities account for less than one percent of total CH_4 emissions from the oil industry.
- *Crude Oil Refining*. Crude oil refining processes and systems account for only three percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries.

Natural Gas Systems

- *Field Production*. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 34 percent of CH_4 emissions from natural gas systems in 2003.
- *Processing*. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of CH_4 emissions from natural gas systems.
- *Transmission and Storage*. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Methane emissions from transmission and storage sector account for approximately 32 percent of emissions from natural gas systems.
- *Distribution*. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Distribution system emissions, which account for approximately 22 percent of emissions from natural gas systems, result mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel). An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.

Appendix C. Transportation Energy Use[42]

The transportation sector is a major source of GHG emissions in New Mexico – large distances, dispersed population and export-based industry lead to high transportation demand and energy consumption (NMDOT 2004)[43]. New Mexico has the largest State road system, measured in lane miles, of all the Rocky Mountain States.[44] Arizona, Utah and Colorado have higher annual vehicle miles traveled (VMT) than New Mexico due to higher populations but New Mexico has a much greater fraction of VMT from freight vehicles (which consume more energy and generate more emissions per mile), much of this for interstate traffic.

By way of comparison, vehicles in New Mexico traveled about 19 billion miles in 2002, compared with 40 billion miles in Colorado. However 19% of the VMT in New Mexico was from freight, compared with 8% in Colorado – indicating similar total freight VMT in each state.[45] According to the *New Mexico 2025 Statewide Multimodal Transportation plan,* "local trucking industry experts predict that commercial truck traffic will double in New Mexico in the next ten years."[46] This report also notes that 85% of commercial traffic on I-10 and I-40 is simply crossing the State, without delivering or picking up any freight.

As shown in Figure 15, these conditions influence the State's GHG emissions. While gasoline consumption, which accounts for the majority of transportation GHG emissions, increased by 26% from 1990 to 2003 (same rate as the population growth), diesel use increased by 77%.[47] Energy consumption and emissions from air travel increased by only 8% during the 1990s, while natural gas and other fuels (accounting for less than 1% of emissions) decreased during this same time period.

Since 1990/91, Bernalillo County has had oxygenate requirements for their winter gasoline that may be met by mixing ethanol with gasoline. Ethanol consumption is deducted from fuel sales reported by EIA SEDS in order to calculate GHG emissions from gasoline use.[48] (Since ethanol is a biomass-derived fuel, its CO2 emissions are not typically counted in inventory assessments.[49])

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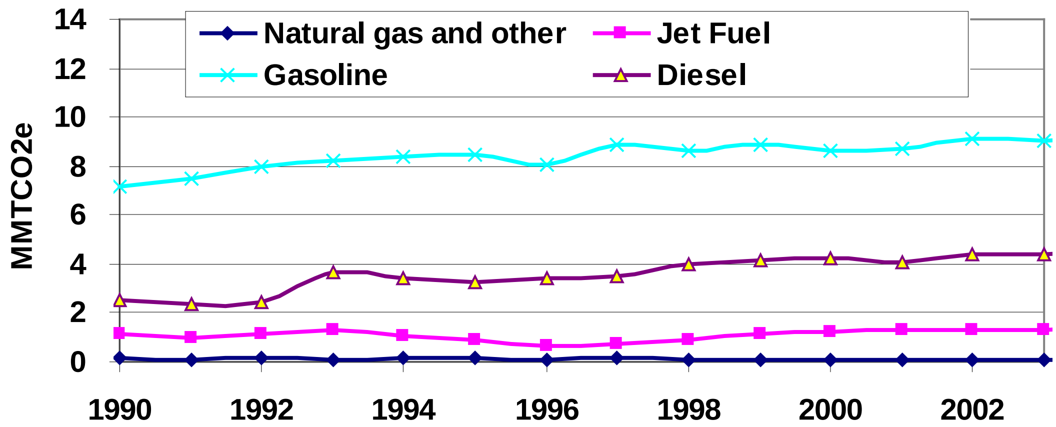
[42] The Transportation and Land Use Technical Working Group reviewed the GHG inventory and forecast, and the corresponding assumptions, for the transportation sector. In particular, this group discussed and reviewed the assumptions regarding gasoline fuel economy and the growth in freight VMT. After this review, the group recommended that the inventory and forecast be accepted with no changes.
[43] NMDOT 2005. *New Mexico 2025 Statewide Multimodal Transportation Plan.* http://www.nmshtd.state.nm.us/upload/images/Long_Range_Planning_Section/GuidingPrinciples/FulfillingNMDOTs_GuidingPrinciples.pdf
[44] 27,346 lane miles, compared with the Rocky Mountain state average of 17,744 lane miles
[45] Data from NMDOT 2004 *Facts and Figures 2004* http://www.nmshtd.state.nm.us/upload/images/pdf/factsandfigures.pdf
[46] Page 31, NMDOT, 2005.
[47] Data from NMDOT (personal communication, R. Olcott) and EIA SEDS show similar trends in gasoline and diesel consumption.
[48] Based on information regarding the months ethanol is blended (4), and oxygenate requirements (7.7%), ethanol consumption is estimated at 12 million gallons in 1990 and 73 million gallons in 2003.
[49] Nonetheless, ethanol, like gasoline, can require significant upstream GHG emissions in production and refining.

Figure 15. GHG Emissions by Fuel, 1990-2003



Source: NM DOT for gasoline and diesel and EIA SEDS for all other fuels. Increase in diesel use in 1993 may be an artifact of data collection methods and needs to be double-checked.

GHG emissions from transportation are expected to grow considerably over the next 15 years due to population growth and increased demand on transportation services. New Mexico studies suggest vehicle miles traveled (VMT) will continue to grow faster than population.[50] As a simplifying assumption, it is projected that energy consumption per VMT (i.e. vehicle fuel economy) will remain constant from 2002 to 2020. The assumption of constant energy per VMT is a place-holder until better information is available for New Mexico.[51] Other assumptions are listed in Table 14.

These assumptions combine to produce more than a 50% increase of transportation sector GHG emissions from 2000 to 2020. Diesel consumption shows the greatest increase (80%), due to the assumed growth in VMT. Both jet fuel and gasoline are expected to increase at slightly more than population growth.

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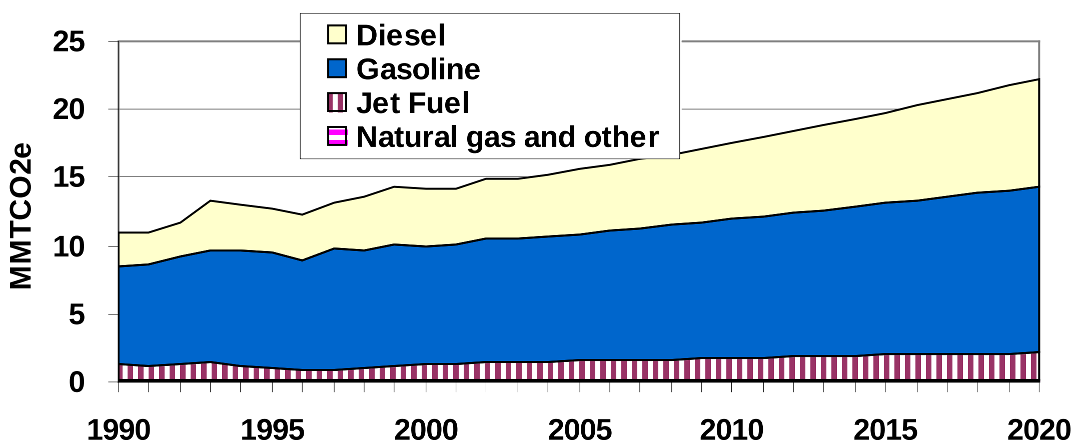
[50] The *New Mexico 2025 Statewide Multimodal Transportation Plan* is the primary source for VMT growth estimates. This report assumed average annual growth of 1.8% per year (an analysis for the area surrounding and including Bernallilo County assumed VMT growth rate of 1.9% per year (B Ives per com 2005). As reported at the start of the appendix, the *2025 Statewide Plan* indicates that some experts are projecting freight VMT to double over the next ten years – this implies an annual growth rate of 7.3%. However, that rate was not used in the analysis in the *2025 Statewide Plan*. The projections reported here use a 3.6% growth rate for freight VMT, an intermediate point between the personal VMT projections and the assumed doubling in 10 years. This growth rate is twice the rate of personal VMT growth, but half the rate of that implied by doubling in 10 years. Further analysis is suggested here.

[51] Neither the Mid-County Council County of Government planners nor the NMDOT planners project energy consumption directly. EIA AEO2005 shows this rate declining for both the country and the Rocky Mountain region.

Table 14. Key Assumptions and Methods for Transportation Projections

Passenger VMT growth	The average annual growth rate for VMT is assumed to be 2% from 2002 to 2020, based on *New Mexico 2025* report.
Gasoline consumption	Gasoline use is assumed to grow with passenger VMT; no change in gasoline use per VMT is assumed.
Ethanol consumption	Average annual ethanol consumption is assumed to remain at 0.7% of total gasoline consumption (representing Bernalillo county winter fuel requirements).
Freight VMT growth	The average annual growth rate for VMT is assumed to be 3.6% from 2002 to 2020.
Diesel consumption	Diesel use is assumed to grow with freight VMT; no change in diesel use per VMT is assumed.
Aviation fuel, jet fuel, natural gas and propane	The average annual growth rates for these fuels are based on EIA AEO2005 growth rates for region (2.5% for aviation gasoline and jet fuel, 0% for natural gas and 5% for propane). Ethanol consumption is projected to grow by 7.8% per year (EIA AEO2005).

Figure 16. Transportation GHG Emissions, 1990-2020



Key uncertainties

With respect to the historical inventory, uncertainties with respect to transportation fuel use and emissions are relatively low. Fuel use estimates are based on NMDOT data drawn from tax receipts, and USEPA fuel-specific CO2 emission factors are relatively accurate. The principal uncertainties, not surprisingly, relate to projections of future emissions, in particular the projected rate of VMT growth for freight and passenger vehicles. In particular for freight VMT, there are significant differences between what EIA projects for the region and the implications of the ten-year doubling in truck traffic projected by NM DOT. Discussions are underway with staff at the Strategic Planning Bureau of NMDOT and the Mid-County Council of Governments to resolve some of these differences.

Another key uncertainty is projected energy consumption per VMT. Since many of the issues that have high importance for planners (congestion, local air pollution) are only indirectly related to energy consumption, estimates for this information for New Mexico may not be available from local transportation planning offices.

Appendix D. Residential, Commercial, and Non-Fossil Fuel Industrial Energy Use[52]

This appendix reports GHG emissions from fuel consumption in the residential, commercial[53] and non-fossil fuel industrial (RCI) sectors. GHG emissions from non-energy sources (such as cement production) are reported in Appendix E, while emissions from the fossil fuel industries are reported in Appendix B.[54] The RCI sectors emit carbon dioxide, methane, and nitrous oxide emissions as fuels are combusted for space heating, process heating, and other applications. Carbon dioxide accounts for over 99% of these emissions on a tCO2e basis.

Direct use of coal, oil[55], natural gas, and wood[56] in these sectors resulted in about 7 MMTCO2e of GHG emissions in 2002. Since these sectors consume electricity, one can also attribute emissions from electricity consumption to these sectors.[57] If electricity-related emissions are included, then these sectors account for nearly 28 MMTCO2e in 2002, with electricity use accounting for three-fourths of RCI emissions. If past trends continue – relatively rapid growth in electricity use combined with slower growth in the use of gas, oil, and coal – electricity will increasingly dominate the RCI sectors in New Mexico both in terms of energy use and GHG emissions.

Overall electricity consumption for the three sectors increased by an average of 2.8% per year from 1990 to 2002; electricity-related emissions grew at a slower annual rate of 2.2%, as emissions per kWh declined (see Appendix A). Nearly half of direct fuel use occurs within the industrial sector, and this has declined in recent years, mostly likely due to decreased activity in the mining and smelting industries.

Reference case emissions GHG estimates depend upon projections of energy use by sector and source. As described in Appendix A, overall, New Mexico electricity use is projected to grow at 2.5% per year, only slightly slower than in the past decade. Lacking detailed projections for the

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[52] The Residential, Commercial, and Industrial Technical Working Group reviewed the GHG inventory and forecast, and the corresponding assumptions, for these sectors. After this review, the group recommended that the inventory and forecast be accepted with no numerical changes, and suggested the addition of Box 1 shown in Section 1 of the report.

[53] The commercial sector "consists of service-providing facilities and equipment of: businesses; Federal, State, and local governments; and other private and public organizations, such as religious, social, or fraternal groups. The commercial sector includes institutional living quarters. It also includes [energy consumed at] sewage treatment facilities" EIA 2002. *State Energy Data 2001, Technical Notes*, page 5. http://www.eia.doe.gov/emeu/states/sep_use/notes/use_intro.pdf

[54] Efforts were made to ensure that fuel use by fossil fuel industries reported in Appendix B are not included (i.e. double counted) in this section.

[55] Propane (aka LPG or liquid petroleum gas) use is included in oil consumption.

[56] Emissions from wood combustion include only N2O and CH4. Carbon dioxide emissions from biomass are assumed to be "net zero" consistent with USEPA and IPCC methodologies, and any net loss of carbon stocks due to biomass fuel use should be picked up in the land use and forestry analysis.

[57] One could similarly allocate consumption-basis GHG emissions from gas, oil, and coal production, however this would have a much smaller effect, as upstream emissions are typically only about 5-25% of combustion-related emissions on a tCO2e per BTU basis.

State, it is further assumed, for the purposes of this initial analysis, the relative growth rates among individual RCI sectors will follow a pattern similar to recent history, as illustrated in Table 15.

Growth rates for natural gas consumption are based on projections from Public Service Company of New Mexico (GDS Associates Inc 2005).[58] For the direct use of coal and oil, regional projections from the EIA Annual Energy Outlook 2005 are used, and adjusted for New Mexico's growth rates of population and employment, resulting in the growth rates shown in Table 16.

Table 15. Electricity Sales Annual Growth Rates, Historical and Projected

Sector	1990-2002	2002-2020
Residential	3.3%	2.9%
Commercial	3.3%	3.0%
Industrial	1.6%	1.4%
Total	**2.8%**	**2.5%**

Table 16. Projected Annual Growth in Energy Use, by Sector and Fuel, 2002-2020

	1990-2002	2002-2010	2010-2015	2015-2020
Residential				
natural gas	1.2%	2.2%	2.2%	2.2%
petroleum	6.1%	1.8%	1.6%	1.0%
Commercial				
natural gas	-1.0%	2.4%	2.4%	2.4%
petroleum	0.4%	2.5%	1.2%	0.5%
Industrial				
natural gas	2.4%	0.2%	0.2%	0.2%
petroleum	-1.7%	3.8%	1.4%	1.1%
coal	6.1%	1.2%	-0.6%	-0.7%

Figure 16, Figure 17, and Figure 18 illustrate historical and projected emissions for the residential, commercial, and industrial sectors from 1990 to 2020. Electricity consumption accounts for the largest component of each sector's emissions. Both the residential and commercial sectors show significant growth in emissions from 2002 to 2020, due to assumed strong growth in both electricity and natural gas consumption. In the residential sector energy consumption grows at slightly faster rate than population growth, a reflection of increased affluence and service provision (more appliances, etc.). In the commercial sector, electricity consumption outpaces employment while natural gas consumption increases at about the same rate as employment.

[58] GDS Associates Inc. 2005 *The Maximum Achievable Cost Effective Potential for Natural Gas Energy Efficiency in the service area of PNM.* Final Report for PNM, submitted April 30, 2005.

Industrial sector emissions 1990 to 2002 vary from year to year, reflecting variations in business activity. From 2002 to 2020, the assumed growth rate for industrial sector electricity consumption is about half the employment growth with very low growth for natural gas consumption. For both the commercial and industrial sectors energy consumption and resulting GHG emissions are expected to grow at a slower pace than State economic activity, indicating an overall decrease in GHG intensity.[59]

Figure 17. Residential Sector GHG Emissions from Energy Use

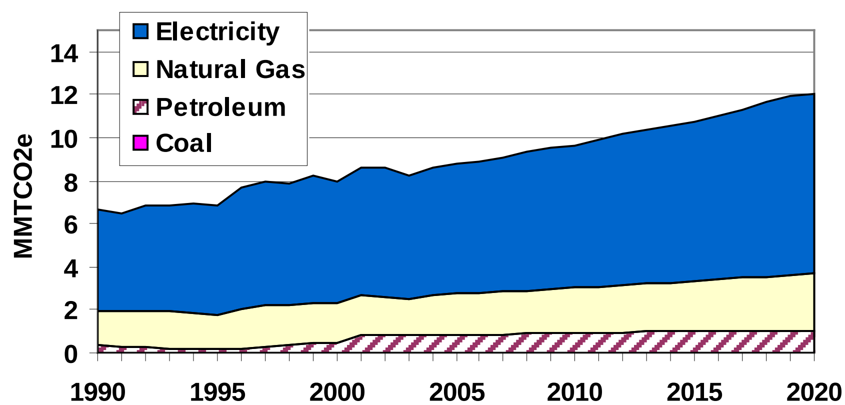
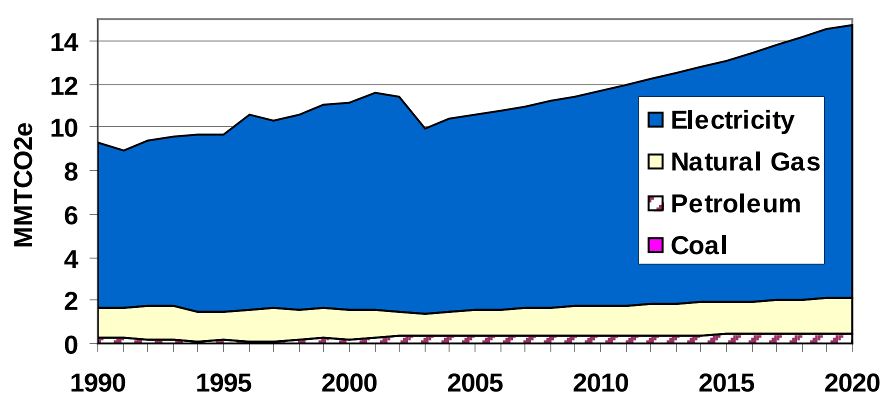
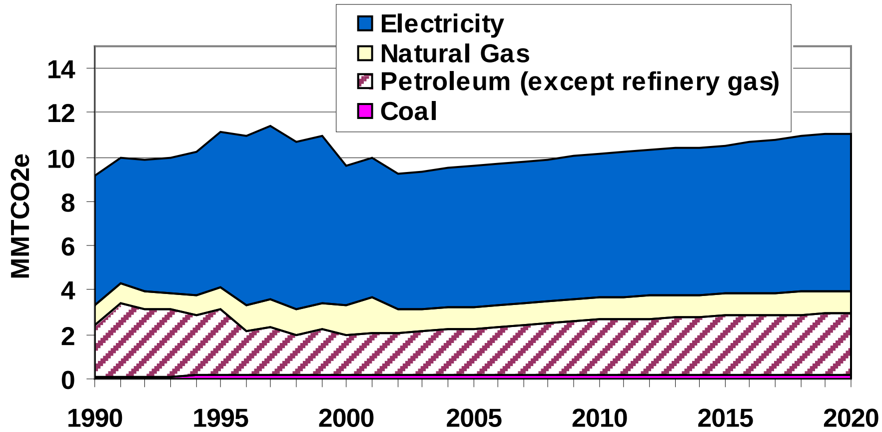


Figure 18. Commercial Sector GHG Emissions from Energy Use



[59] These estimates of growth relative to population and employment reflect expected responses – as modeled by PNM, other electric utilities and the EIA NEMS model -- to changing fuel and electricity prices and technologies, as well as structural changes within each sector (subsectoral shares, energy use patterns, etc.).

Figure 19. Industrial Sector GHG Emissions from Energy Use



Key Uncertainties

Key sources of uncertainty underlying the inventory and projections are as follows:

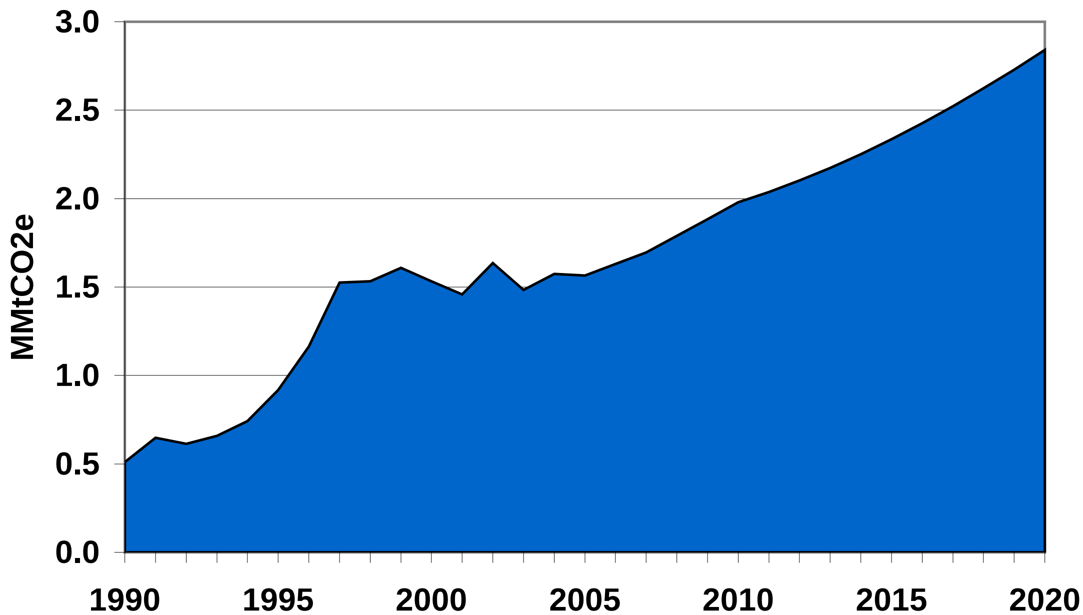
- Population and economic growth are the principal drivers for electricity and fuel use and are subject to significant uncertainties.
- The projections assume no large long-term changes in relative fuel and electricity prices, as compared with current levels and US DOE projections. Should changes would influence consumption levels and encourage switching among fuels.
- It is assumed that energy consumed at military bases and national laboratories are included in the energy statistics from the EIA. However, under-reporting may have occurred but estimating that impact is beyond the scope of this effort.
- Growth of major industries – the energy consumption projections assume no new large energy-consuming facilities and no major changes in mining activity. A few large new facilities – or the decline of major industries – could significantly impact energy consumption and consequent emissions.

Appendix E. Industrial Process and Related Emissions[60]

Emissions in this category span a wide range of activities, and reflect non-combustion sources of CO2 from industrial manufacturing (cement, lime, and soda ash production), the release of hydrofluorocarbons (HFCs) from cooling and refrigeration equipment, the use of various fluorinated gases in semiconductor manufacture (perfluorocarbons or PFCs as well as HFCs), and the release of sulfur hexafluoride (SF6) from electricity transformers.

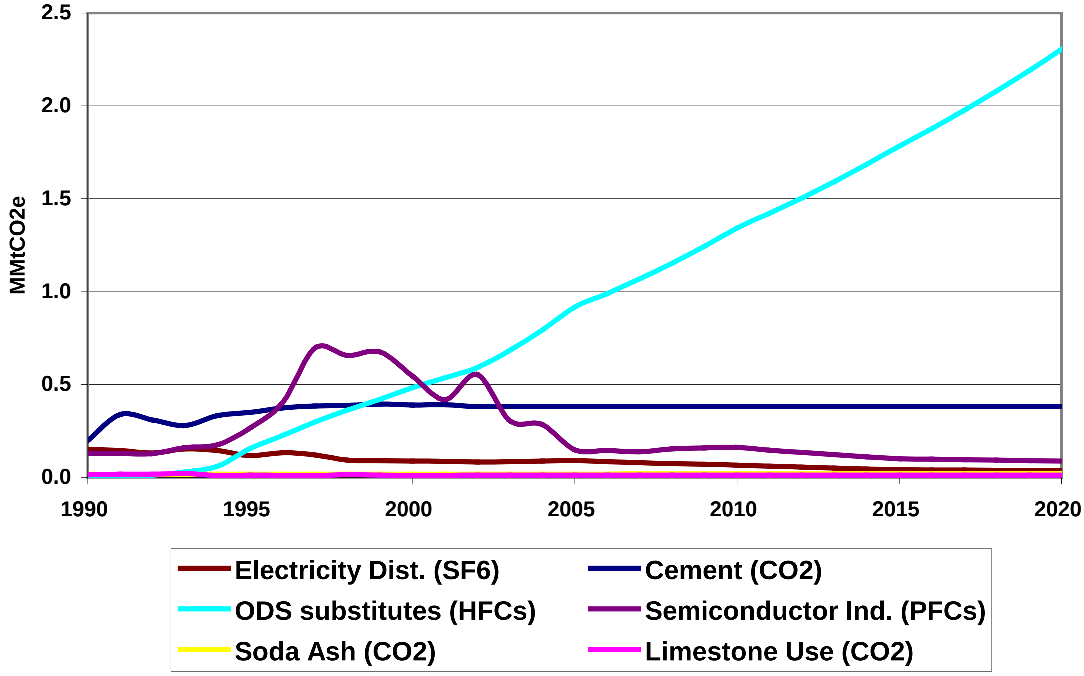
Overall industrial processes and related emissions as shown in Figure 19, more than tripled from 1990 to 2000 and are expected to continue to grow through 2020. The contributions of each sub-category are shown in Figure 20 and explained below.

Figure 20. GHG Emissions from Industrial Processes, 1990-2020



[60] The assumptions and results shown in this section were reviewed and accepted by the Residential, Commercial, and Industrial Technical Working Group.

Figure 21. GHG Emissions from Industrial Processes, 1990-2020, by Source



From 1990 to 2005 the semi-conductor industry was one of the largest contributors of GHG emissions from industrial processes. These emissions peaked in 1997 but have decreased significantly since then – largely due to voluntary actions by the industry. Intel, the largest manufacturer in New Mexico, provided estimates of its PFC emissions from 1995 to 2004, along with projections to 2010; no estimates were obtained for other manufacturers. Emissions beyond 2010 could increase due to increases in semi-conductor manufacturing, or decrease due to process change and/or continued industry efforts to reduce emissions. Projections from the US Climate Action Report[61] shows expected decreases in PFC emissions at the national level due to a variety of industry actions to reduce emissions, and the rate of decline from that report was applied for emissions from 2010 to 2020.[62]

After 2005, emissions from HFCs in refrigeration and air conditioning equipment dominate the category and show strong growth through 2020. HFCs are being used to substitute for ozone-depleting substances (ODS), most notably CFCs (also potent warming gases) in compliance with the *Montreal Protocol*.[63] Even low amounts of HFC emissions, from leaks and other releases

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[61] U.S. Department of State, *U.S. Climate Action Report 2002*, Washington, D.C., May 2002. http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/SHSU5BNQ76/$File/ch5.pdf

[62] Similarly, the Intel data was extrapolated back to 1990, based on 1995 data from Intel and annual change in the national emissions from the US inventory (US EPA 2005 *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003*)

[63] ODS substitutes are primarily associated with refrigeration and air conditioning, but also many other uses such as fire extinguishers, solvent cleaning, aerosols, foam production ns for ODS substitutes depend on technology characteristics in a range of equipment. For the US national inventory, a detailed stock vintaging model was used, but such analysis has not been completed at the state level. This report uses the EPA SGIT procedure of estimating state-level emissions based on the state's fraction of US population and the US

under normal use of the products, can lead to high GHG emissions. Emissions from the ODS substitutes in New Mexico are estimated to have increased from 0.002 MMTCO2e in 1990 to 0.5 MMTCO2e in 2000, with further increases of 8% per year expected from 2000 to 2020. The estimates for the emissions in New Mexico are based on the State's population and estimates of emissions per capita from the US EPA national GHG inventory.[64]

Emissions of SF6 from electrical equipment have experienced declines since the early-nineties (see Figure 20), mostly due to voluntary action by industry. Emissions for New Mexico from 1990 to 2003 were estimated based on the estimates of emissions per kWh from the US EPA GHG inventory (US EPA 2005 *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2003*) and New Mexico's electricity consumption. The US Climate Action Report[65] shows expected decreases in these emissions at the national level, and the same rate of decline is assumed for emissions in New Mexico The decline in emissions in the future reflects expectations of future actions by the electric industry to reduce these emissions.

Cement production emits CO2 during the calcination process, whereby calcium carbonate (CaCO3) is converted to calcium oxide (CaO). This process also requires significant energy consumption; emissions related to fuel use at cement plants are reported in the RCI section above. The process emissions are directly related to the amount of clinker and masonry cement produced. New Mexico has one cement plant, GCC Rio Grande. For 1990-2002, GHG emissions are calculated as the production from this plant by a standard emission factor of 0.507 tons CO2/ton clinker.[66] Although cement consumption in New Mexico is likely to increase with increased population, much of the cement is supplied from a plant in Mexico. Therefore, pending further analysis and review, no changes in in-state cement production are assumed after 2002.

Emissions from lime manufacture, which also emits CO2 from chemical conversion, have not yet been estimated. Like cement, New Mexico has one lime plant. Production data for this plant are confidential. Thus to develop a rough initial estimate, emissions from limestone use (as well as soda ash) production are based on reported in-state consumption data from the United States

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emissions. Growth rates are based on growth in projected national emissions from recent EPA report, US EPA 2004, *Analysis of Costs to Abate International ODS Substitute Emissions,* EPA 430-R-04-006.

oduction ns for ODS substitutes depend on technology characteristics in a range of equipment. For the US national inventory, a detailed stock vintaging model was used, but such analysis has not been completed at the state level. This report uses the EPA SGIT procedure of estimating state-level emissions based on the state's fraction of US population and the US emissions. Growth rates are based on growth in projected national emissions from recent EPA report, US EPA 2004, *Analysis of Costs to Abate International ODS Substitute Emissions,* EPA 430-R-04-006. http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR62AS98/$File/IMAC%20Appendices%206-24.pdf

[65] U.S. Department of State, *U.S. Climate Action Report 2002*, Washington, D.C., May 2002. http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/SHSU5BNQ76/$File/ch5.pdf

[66] Annual production from the cement plant was not available so values were estimated as follows. The *New Mexico Greenhouse Gas Action Plan* (WERC 2002) provided estimates of cement production from this plant in 1997 and the United States Geological Survey (USGS) *Cement Annual* lists cement production data for Arizona and New Mexico combined together (for confidentiality reasons). As a first approximation, the fraction of New Mexico production to total Arizona and New Mexico production was calculated for 1997. This same fraction was applied to the USGS value for 1990-2002 to estimate New Mexico cement production.

Geological Survey (USGS). These rough estimates, suggest emissions from these two sources accounted for less than 4% of industrial process emissions in 1990 and have not grown significantly since. The assumed trend is for these emissions to remain at 2002 levels through 2020.

Key Uncertainties

Since emissions from industrial processes are determined by the level of production and the production processes of a few key industries, there are is relatively high uncertainty regarding future emissions, as they depend on the competitiveness of New Mexico manufacturers, the specific nature of their production processes.

The projected largest source of future industrial emissions, HFCs used in cooling applications, is subject to a number of uncertainties as well. First, historical emissions are based on national estimates; New Mexico-specific estimates are currently unavailable. Second, emissions will be driven by future choices regarding air conditioning technologies and coolants used, for which a number of options currently exist.

Appendix F. Agriculture, Forestry and Other Land Use[67]

The emissions discussed in this appendix refer to non-energy emissions from agriculture, forestry and other land uses. These emissions include emissions from livestock, agriculture soil management and field burning, CO2 emitted and removed (sinks) due to forestry activities and land use change, and emissions linked to rangeland and forest fires.

Figure 22. GHG emissions from Agriculture, Forestry and Other Land-Use (MMTCO2e)

Reference Case GHG Emissions for New Mexico

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Agriculture, Land Use, and Forestry	**-16.4**	**-15.0**	**-14.5**	**-14.2**	
Agriculture (CH4 & N20)	4.5	6.0	6.4	6.7	Assumes dairy production grows at same rate as population and no growth in other areas after 2004
*Forestry and Land Use	-20.9	-20.9	-20.9	-20.9	Carbon sequestration rates are assumed to remain constant.

Agriculture

Agriculture plays a large role in New Mexico's economy, contributing about $2 billion in annual crop and livestock sales. In 2002, dairy products accounted for $744 million in sales – this industry has grown strongly in the last decade, from ranking 30th state in the country in dairy production in 1990 to 7th in 2002. Cattle sales accounted for $593 million while crops (including feed for stock) made up another $575 million.[68]

GHG emissions from livestock, agriculture soil management and field burning were about 6.2 MMTCO2e in 2004. These emissions include CH4 and N2O emissions from enteric fermentation, manure management, agriculture soils and agriculture residue burning. Data on crops and animals in the State from 1990 to 2004 were obtained from the USDA National Agriculture Statistical Service.[69] As shown in Figure 22, emissions from these sources increased by about 37% from 1990 to 2004. Emissions from agricultural soils accounted for the largest fraction (about 50%) of agricultural emissions in 1990. Soil-related emissions of N2O occur as the result of activities that increase nitrogen in the soil, including fertilizer (synthetic, organic and livestock) application and the production of nitrogen-fixing crops. These activities remained relatively stable from 1990 to 2004 and consequently emissions increased by only 3% between these years.

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[67] The Agriculture and Forestry Technical Working Group reviewed and accepted the assumptions and results shown in this section.

[68] *Agricultural Facts 2002* http://nmdaweb.nmsu.edu/DIVISIONS/AGSTATS/2002/2002%20Ag%20Facts.pdf and *Dairy Facts 2002*, http://nmdaweb.nmsu.edu/DIVISIONS/AGSTATS/2002/2002%20Dairy%20Facts.pdf

[69] Personal communication from NM office of National Agricultural Statistics Service to NMENV May 2005 indicated that the NASS website had the best data on agriculture stocks, data are collected in state and compiled for the NASS site.

Enteric fermentation and manure management accounted for about 42% and 8% of agriculture emissions in 1990, respectively. Enteric fermentation is another term for the microbial process of breaking down food in digestive systems, which results in methane emissions that are especially large among ruminants, such as cattle and sheep. Largely as the result of the expansion of dairy farming in New Mexico, enteric fermentation emissions increased by 24% from 1990 to 2004 – and now appear to exceed GHG emissions from agricultural soils.

Of the agricultural emissions sources, manure management emissions have risen the most rapidly– almost tripling from 1990 to 2004. This large increase reflects the growth in the dairy industry – the number of dairy cows in New Mexico increased from about 90 thousand head in 1990 to almost 400 thousand head in 2004 (in contrast the number of beef cattle declined by about 10%).[70] Emissions from agriculture residue burning are very small and decreased by 26% from 1990 to 2002.

As a first approximation for projecting emissions from this source, the growth rate for dairy cattle is assumed to match the State population growth rate, 1.2% per year. This rate is lower than the growth from 1995 to 2004 of 6.5%, and reflects constraints to continued rapid growth, such as expected higher costs for future water rights and gasoline, along with increased productivity per animal. For other animal stock, a simple assumption of no change from 2004 levels was applied. It is also assumed that emission rates per animal (based on animal weight, feed and management strategies for stock and land) remain at the 2004 levels.

As illustrated in Figure 22, total GHG emissions from agriculture increased by 32% from 1990 to 2000, and are projected to increase another 13% by 2020.

Forestlands

Forest land emissions refer to the net CO_2 flux[71] from forested lands in New Mexico, which account for about 27% of the State's land area. These net forest and land use sequestration estimates are based on recent improvements to US Forest Service carbon stock inventory from earlier estimates published in 1997 by Birdsey and Lewis.[72] Updated results include a more accurate definition of the year in which data was actually collected (some 1987 data was earlier reported as 1982), and updated tree biomass and soil carbon calculations based on new field studies.

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[70] While beef cattle significantly outnumber dairy cows in New Mexico, the number of dairy cows has grown rapidly. While total cattle grew by 11% during this period, enteric fermentation emissions increased by 24% and manure management by 310%. Per animal enteric fermentation emissions are somewhat higher for dairy cows and manure management emissions are substantially higher, due to anaerobic conditions created by manure collection systems at dairy farms. Note that these figures do not consider a reported 6,000 animal population of domesticated bison, whose enteric fermentation emissions probably exceed beef cows. Also, to the extent dairy operations are using dry waste-management (feedlot) systems, SGIT may overestimate manure management emissions. Methane and nitrous oxide emissions from agricultural residue burning were calculated using default values in SGIT. More specific information on the amount of residue burned in New Mexico might be available in the future from NMED's Smoke Management Program, which requires tracking and reporting of such burning.

[71] "Flux" refers to both emissions of CO_2 to the atmosphere and removal (sinks) of CO_2 from the atmosphere.

[72] Thomas D. Peterson, James E. Smith and Jack D. Kartez (2005). Development of Forestry Related Climate Change Mitigation Options for the State of Maine. The Journal of Environmental Quality (available in prepublication format).

Figure 23. GHG Emissions from Agriculture

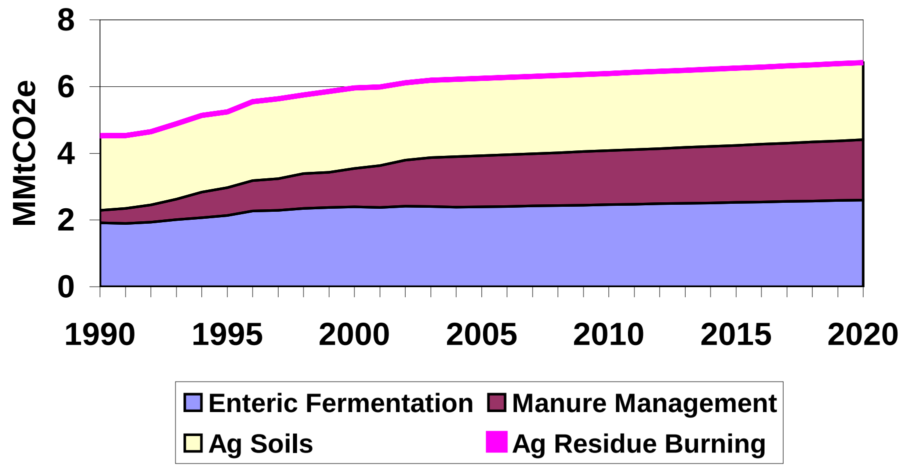

Table 17. GHG Emissions (Sinks) from Forestry and Other Activities

	1990	2000
Live and dead-standing trees and understory	-13.6	-13.6
Forest floor and coarse woody debris	-3.1	-3.1
Soils	-5.9	-5.9
Wood products and landfills	1.8	1.8
Total	**-20.9**	**-20.9**

Additional land cover change, wood products, and import/export estimates from secondary sources could change current results. The Technical Workgroup did not identify any changes that could be made within the time and resource constraints for this project. According to the US Forest Service there are no methods available to correct for changes in the definition of forestland that occurred during the FIA survey period. During the FIA survey periods used for carbon stock estimates, the definition of forestland changed from a minimum forest cover requirement of 10% to a minimum of 5%. As a result, differences occur in the number of forested acres simply as a result in the change of input data. Also, rangelands may or may not be included in these estimates of forested area, depending on their level of tree stocking. Finally, Data is not available from FIA for years 1997-2002 due to lack of state funding for USDA Forest Service inventory of lands in New Mexico.

Uncertainties and Further Analysis

US Forest Service assessments only cover the parts of the State that the US Forest Service defines as forest, representing 27% of the total State land area in 1997. To the extent that they may sequester or emit carbon, while small on a per acre basis, rangelands may be quite significant at the State level.[73] While modeling methods exist to quantify inter-annual carbon pools for rangelands (and hence the level of carbon flux), time and resource constraints did not allow for the Technical Workgroup to develop estimates for rangelands. It is recommended that future analyses explore carbon flux for rangelands.

Due to funding constraints in New Mexico, US Forest Service data from the FIA are not available for the 1997-2002 period. As a result, biomass reductions from wildfires and forest health problems, or other carbon stock changes during this period, are not reflected in the averages reported for the previous decade. The current forecasts for forest carbon projections are based solely a linear extrapolation of the 1987-1997 period for which data are available. Future research should explore the impacts on carbon sequestration of projected forest health, forest products usage, and other forestry management programs.

[73] However, the carbon cycle for rangelands is not well understood, and has not been included in current surveys.

Appendix G. Waste Management

GHG emissions from waste management are summarized in Table 18. Emissions in this category include:

- Solid waste management – methane emissions from landfills, accounting for any methane that is flared or captured for energy production, and
- Wastewater management – methane and nitrous oxide from municipal wastewater treatment facilities.

Any emissions associated with energy consumed to transport of solid waste and wastewater are included in the RCI accounting above.

Table 18. Emissions from Waste Management

Reference Case GHG Emissions for New Mexico

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Waste Management	**0.8**	**1.2**	**1.4**	**1.2**	
Solid Waste Management	0.6	1.0	1.1	0.9	Based on national projections (US DptState)
Wastewater Management	0.2	0.2	0.3	0.3	Increases with state population

The EPA SGIT tool was used to estimate solid waste management emissions from 1990 to 2003.[74] However, since emissions from these types of facilities are site-specific, we are also working with NMED to determine if better estimates exist. The information in the EPA SGIT tool was updated with data from NMED on waste generated and imported into the State from 1993 to 2003. Further discussion are underway with the NMED and landfill operators to check the emissions avoided by flaring at Camino Real, Cerro Colorado, Los Angeles landfill in Albuquerque and other landfills.

For emissions from 2004 to 2020, growth rates are based on national projections by the US Department of State.[75] These projections decrease over time, accounting for improved methane recovery practices. Conversations with NMED indicate that 5-6 new landfill gas recovery systems are likely to be added to New Mexico landfills over the next 5 years, supporting the assumptions of decreased landfill emissions even accounting for increased solid waste generation as population grows.

Emissions from wastewater were also estimated using the EPA SGIT tool. These emissions increased by 1.9% per year from 1990 to 2003.[76] Projected emissions are assumed to increase with population growth, 1.2% per year from 2004 to 2020.

[74] EPA SGIT uses amount of waste in place at landfills, characteristics of landfill (size, moisture levels), amount of landfill gas recovered and flared and oxidation levels to estimate state emissions from landfills.
[75] US Department of State (2002). *US Climate Action Report 2002.* Washington DC May 2002.
[76] Emissions are calculated in EPA SGIT based on state population, assumed biochemical oxygen demand and protein consumption per capita, and emission factors for N2O and CH4.

Appendix H. List of Contacts Made (may be incomplete)

Lany Weaver, New Mexico Environment Department (NMED), Air Quality Bureau (AQB)
Brad Musick, NMED, AQB
Mary Uhl, NMED, AQB
Rita Trujillo, NMED, AQB
Erik Aaboe, NMED, AQB
Ted Schooley, NMED, (electric plant permits)
Sam Speaker, NMED, (electric plant permits)
John O'Connell, NMED, (solid waste bureau)
Lawrence Alires, NMED, (air quality bureau)

Craig O'Hare, Energy, Minerals and Natural Resources Department (EMNRD), Energy Conservation and Management Division
Chris Wentz, EMNRD, Energy Conservation and Management Division
Dan Hagan, EMNRD, Energy Conservation and Management Division

Jeff Fredine, NM Department of Highways

Pat Oliver-Wright, NM Department of Transportation (NMDOT), long range planning
Roy Cornelius, NMDOT (long range plan)
Elizer Pena, NMDOT (historic VMT)
Becky Valencia, NMDOT (historic VMT)
Bo Olcott, NMDOT, (fuel consumption)
Berry Ives, Mid-Region Council of Governments of NM (long term plan for Bernalillo county)

Barbara Vial, NM Public Regulation Commission, Utility Division
Prasad Potuturi, NM Public Regulation Commission, Utility Division
Elisha Leyba, NM Public Regulation Commission, Utility Division
Lonnie Montoya, NM Public Regulation Commission, Pipeline Safety

Jeffrey Burks, Public Service of New Mexico

Frank E. Gallegos, Intel Corporation

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Jim Smith, US Forest Service

James Russell, Environ Corporation

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