COLORADO

Air Pollution Control Division

Department of Public Health & Environment

Colorado

2021 Greenhouse Gas Inventory Update

Including Projections to 2050

DRAFT PUBLICATION

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EXECUTIVE SUMMARY

The 2021 Colorado Greenhouse Gas (GHG) Inventory Update, including 5-year projections through 2050, is a summary of Colorado's estimated greenhouse gas (GHG) emissions and sinks from 2005 to 2050. Prior to this update, the GHG Inventory was most recently updated in 2019, per the five-year inventory update requirement in Executive Order (EO) #D-004-08 issued on April 22, 2008 under then-Governor Bill Ritter, Jr.

The 2021 inventory update retains some data and information from the 2019 inventory due to the close proximity in time of the two reports. For more information, see discussion of the State Inventory Tool (SIT) model below. However, in late October 2020, EPA released updates to the SIT that includes notable changes to certain modules, such as the Land-use, Land-use Change, and Forestry (LULUCF) module, which has been incorporated into this inventory. The Air Pollution Control Division (Division) will continue to evaluate updates to the other SIT modules for possible incorporation into this inventory before the final version is published later in 2021.

Additionally, the 2021 inventory includes revised emissions estimates and projections for the oil and gas sector based on a detailed analysis conducted by the Division, calendar year 2019 emissions estimates, and updated projections for 2020 through 2050. The 2019-year emissions and forward looking projections are derived from Colorado's GHG Pollution Reduction Roadmap (GHG Roadmap) report. The GHG Roadmap was a collaborative effort across multiple Colorado agencies, led by the Colorado Energy Office, to define an emissions trajectory necessary to achieve Colorado's GHG reduction goals. At the time of release of this draft inventory, the GHG Roadmap is undergoing final review with expected publication in early 2021.[1]

The 2021 inventory also provides a comparison for reference purposes of the impact on Colorado's GHG emissions estimates using global warming potential (GWP) values from the United Nations' Intergovernmental Panel on Climate Change's (IPCC) fourth (AR4)[2] and fifth (AR5)[3] assessment reports (see Exhibits ES-8 and ES-9 below). This inventory uses the AR4 100-year time horizon GWP values for all calculations to align with Colorado and U.S. Environmental Protection Agency (EPA) GHG reporting requirements (see below).

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[1] *https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap*

[2] IPCC AR4 WG1 (2007), Solomon, S.; Qin, D.; Manning, M.; Chen, Z.; Marquis, M.; Averyt, K.B.; Tignor, M.; Miller, H.L.,eds.; Climate Change 2007: The Physical Science Basis, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press.

[3] IPCC AR5 WG1 (2013), Stocker, T.; Qin, D.;Plattner, G.; Tignor, M.; Allen, S.;Boschung, J.; Nauels, A.; Xia, Y.; Bex, V.; Midgley, P., eds.; Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on climate Change, Cambridge University Press.

Senate Bill 19-096 (SB 96), addressing GHG emission data collection, and House Bill 19-1261 (HB 1261), addressing statewide GHG reduction goals, were passed during the 2019 legislative session and signed into law on May 30, 2019. SB 96 directs the Air Quality Control Commission (AQCC) to update the statewide inventory at least every two years and to adopt rules requiring monitoring and public reporting of GHG emissions in support of state GHG reduction goals. The AQCC adopted GHG inventory and reporting requirements for oil and gas under Regulation 7 in December 2019 and September 2020, and a comprehensive statewide GHG reporting rule under Regulation 22 in May 2020, which rely primarily on reporting protocols under EPA's Greenhouse Gas Reporting Program (GHGRP). Initial reporting under these requirements will begin in early-to-mid-2021, and full reporting will begin in 2022. Once these reporting requirements are fully implemented, it is expected that future inventories will reflect improved and more accurate data based on direct reporting which will better inform progress towards state GHG reduction goals. It is also anticipated that more complete understanding of emissions sources, increased on-site monitoring, and the growing availability of aerial detection methods will also provide additional information allowing for further refinement of future inventories.

As noted, the 2021 inventory retains some data and information from the 2019 inventory. The 2019 inventory was completed using the SIT. The SIT model is intended to automate the calculation of emission estimates in a manner consistent with prevailing national and international guidelines. Both the underlying data and the calculation methodologies are periodically updated by EPA, including a recent update that occurred in late October 2020 that the Division will review for making further updates to this inventory. In general, the SIT model uses activity data, emission factors, and GWP factors to estimate historic emissions from the base year of 1990 through the most current year with activity data in the tool (currently 2018). Therefore, to estimate calendar year 2019 emissions, the 2021 inventory relies on the analysis used for the Reference Scenario in the GHG Roadmap ("Reference Scenario"), which accounts for existing sector-specific policies adopted prior to the 2019 legislative session, including the Renewable Portfolio Standard (RPS) for electricity, federal CAFE standards for passenger vehicles, and requirements to address methane emissions from oil and gas production.

For consistency across different reporting programs, the 2021 inventory continues to use the IPCC AR4 GWP factors mandated by EPA in the Greenhouse Gas Reporting Program (GHGRP)[4] for the official inventory.

As noted in the 2019 inventory, there is considerable uncertainty in much of the activity data, emission factors, and many of the calculation methods in the SIT. Calculations are performed at a high level, using a combination of state–level and national input data and often applying a single emission factor to address multiple

[4] 40 CFR 98.2(b)(4) and 40 CFR 98.2 (c)

activities. Activity data is not always consistent over time. For example, there have been changes in how some activity data has been collected and reported and sometimes in the specific types of data collected. A particular production or consumption number in one year may represent different underlying data than it did in a previous year. The emissions quantities generated by the model are estimates only. As a result, it is difficult to use the data generated by the SIT to evaluate the impact of specific policies and regulatory initiatives designed to achieve the GHG reductions goals for Colorado. For this reason, Colorado is moving toward the use of more detailed and specific reported data in future inventories as well as a model designed specifically for Colorado emissions calculations. Nonetheless, the SIT has been used to establish the 2005 baseline for most sectors to compare emission reductions against moving forward. It should be noted that the oil and gas portion of the 2021 inventory, which is not based on the SIT, does reflect statewide regulatory initiatives for that sector over time and is being used to establish the 2005-year baseline for that sector.

The SIT model is a spreadsheet-based set of eleven individual modules for specific sectors/activities and a companion Projection Tool, though the Projection Tool is not being relied on for the 2021 inventory. As a general matter and similar to the 2019 inventory, the 2021 inventory relies on the Colorado default values within the SIT model. While the SIT model provides flexibility to change default values, for the most part the inventory retains the default values, either because there is insufficient data to create customized values, or potential changes to the default values would not materially change the calculated emissions. The only part of the SIT model where default values were not used for the 2021 inventory is for wildfire acres burned under the LULUCF module where state-specific data was relied on.

After the end of a calendar year, activity data such as production and consumption data is collected, reviewed, organized, and published by various state and federal agencies and industry organizations. There is a lag time before such data is available for use. Accordingly, the current version of the SIT model has been updated through 2018. In order to remain consistent with prior GHG inventories released by the Division, data in this inventory is presented at 5-year intervals from 2005 through 2015, plus 2019-year emissions, and then projections for 2020 through 2050. Prior inventories date back to 1990, which is the earliest year calculated by the SIT. However, since 2005 is the baseline year against which GHG reductions must be measured in Colorado as required under HB 1261, this inventory only covers the period from 2005 and on. Again, as noted, the oil and gas production emissions, 2019-year emissions, and 2020 through 2050 projections in this inventory are based on the analyses conducted for the GHG Roadmap.

This report includes multiple chapters, which serve as an outline to better understand the inventory. Each chapter focuses on an individual sector of the inventory (e.g., oil and gas, transportation, agriculture, etc.), explains model or analysis results, data assumptions, and uncertainties. While for the most part the report chapters track the various modules within the SIT model, data from certain modules were either consolidated or split out in order to provide a more cohesive sector-based analysis of GHG emissions in Colorado.

Exhibit ES-1 includes a summary of GHG emissions by sector in Colorado from 2005 through 2019. Exhibit ES-2 shows GHG emissions projections by sector from 2020 through 2050 based on the trajectory developed by the GHG Roadmap to achieve compliance with the statewide goals. Note that these exhibits do not include emissions from Land Use and Forestry. The gases included in the inventory include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and a group of gases including hydrofluorocarbons (HFCs), perfluorinated compounds (PFCs), sulfur hexafluoride (SF_6), and a number of similar compounds. All emissions are reported in terms of million metric tons (MMT) of carbon dioxide equivalent (CO_2e) to account for the different GWP of the gases. The inventory shows that Colorado GHG emissions have decreased slightly between 2005 and 2019. Emissions are projected to continue decreasing more significantly in projection years because of current and anticipated emission reduction initiatives including legislation, regulations, and policy initiatives, dropping by 50% compared to 2005 levels in 2030. Additionally, the data shows that most current and historic GHG emissions in Colorado come from electric power generation, transportation, fuel use for residential, commercial, and industrial applications, and the natural gas and oil systems sector. Together these sectors comprise over 80% of total statewide GHG emissions.

Exhibit ES 1: Estimated Colorado GHG Emissions by Sector 2005 - 2019 ($MMTCO_2e$)

Emissions by Sector ($MMTCO_2e$)	2005	2010	2015	2019
Electric Power	40.291	39.535	36.283	29.759
Transportation	30.787	29.764	28.168	27.436
Residential, Commercial & Industrial Fuel Use	24.643	26.190	25.692	27.176
Natural Gas and Oil Systems	20.166	28.899	19.648	21.930
Agriculture	9.582	10.069	10.660	10.661
Coal Mining & Abandoned Mines	6.810	8.137	1.851	1.823
Industrial Processes	3.154	3.675	4.508	4.656
Waste Management	2.366	3.583	4.186	4.403
Grand Total	137.800	149.852	130.997	127.844

Exhibit ES 2: Projected Colorado GHG Emissions by Sector 2020 - 2050 ($MMTCO_2e$)

Emissions by Sector ($MMTCO_2e$)	2020	2025	2030	2035	2040	2045	2050
Electric Power	24.039	21.000	8.000	6.177	4.295	3.243	2.192
Transportation	25.483	23.000	18.000	9.287	5.245	2.406	0.206
Residential, Commercial & Industrial Fuel Use	27.582	26.000	20.000	13.886	8.492	4.934	2.597
Natural Gas and Oil Systems*	20.767	11.600	7.100	7.109	5.259	3.409	1.559
Agriculture	10.661	10.641	9.673	8.588	7.639	6.690	5.741
Coal Mining & Abandoned Mines	1.819	1.786	0.536	0.197	0.188	0.180	0.173
Industrial Processes	4.694	3.500	2.900	2.602	2.206	1.695	1.057
Waste Management	4.459	3.072	2.031	2.412	2.436	2.454	2.463
Negative Emissions Technologies	0.000	0.000	0.000	-1.056	-1.744	-2.431	-3.119
Grand Total	119.504	100.598	68.241	49.200	34.015	22.579	12.869

Exhibit ES-3 shows the distribution of estimated and projected Colorado GHG emissions by sector. As noted, the highest proportion of emissions from 2005 to 2019 were from the electric power sector despite a major reduction in emissions during that period, primarily due to switching that had occurred from coal to natural gas as a fuel source for electric power generation and increased use of renewable energy. As a result, by 2019, emissions from the transportation sector, which has the next highest proportion of emissions, were just below those from the electric power sector. Furthermore, transportation sector emissions were projected to overtake electric power as the largest single sector of emissions in 2020.

Exhibit ES 3: Estimated Colorado GHG Emissions by Sector 2005 - 2019 ($MMTCO_2e$)

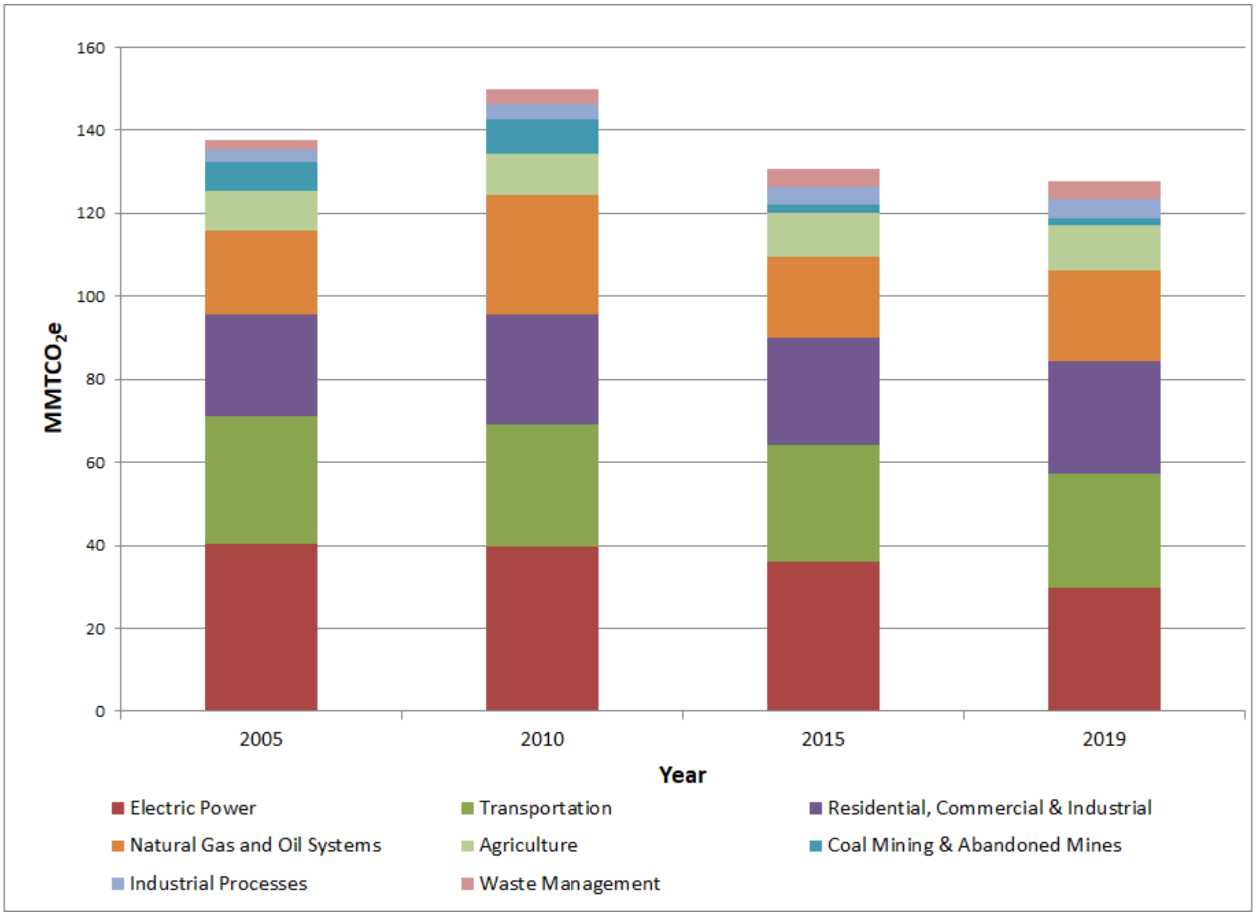
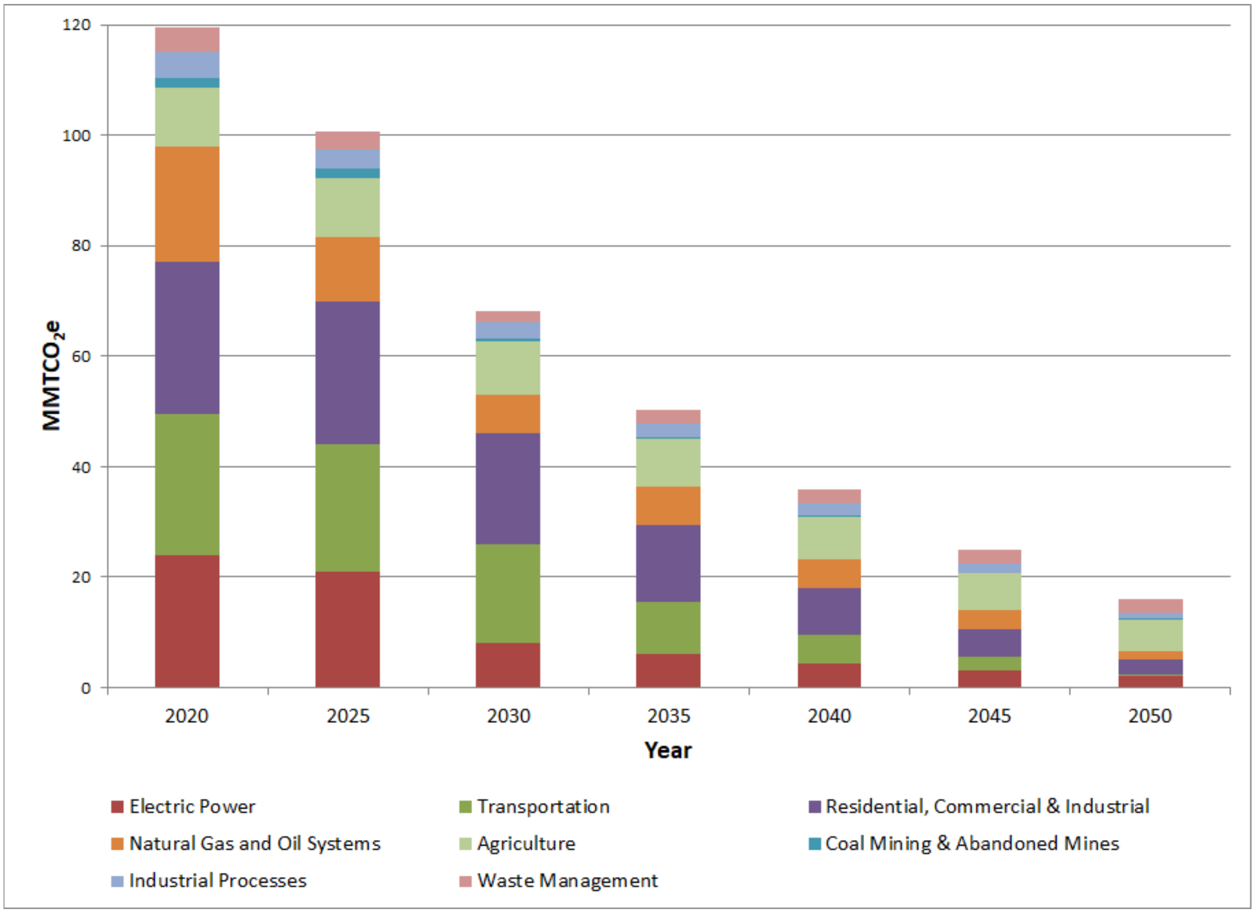


Exhibit ES 4 shows the projected emissions, in 5-year intervals, from 2020 through 2050. The projected emissions in ES 4 are based on work completed for the GHG Roadmap project, further described in Section 3, and outline a general economy-wide emissions trajectory that Colorado legislation, regulation, and policy will need to secure over the next 30 years to achieve the emissions reduction goals outlined in HB 1261. The projections showcase the new approach adopted by Colorado for creating forward looking emissions estimates to guide legislative, regulatory, and policy planning.

Exhibit ES 4: Projected Colorado GHG Emissions by Sector 2020-2050 ($MMTCO_2e$)



Exhibits ES-5 and ES-6 show the breakdown of the estimated historic, current, and projected GHG inventory by gas and sector. These exhibits provide some insight into the proportional contributions of the various greenhouse gases, based on the current global warming potential factors used by EPA. Note that 2019 year emissions are based on estimates from the Reference Scenario in the GHG Roadmap, which may differ from SIT model estimates for prior years. For example, the Reference Scenario did not break out CH_4 and N_2O emissions from the Residential, Commercial, Industrial, Transportation, Electric Power, and Land Use and Forestry sectors.

In 2019, CO_2 accounted for 67% of the inventory, CH_4 accounted for 27% of the inventory, N_2O accounted for 3%, and HFCs, PFCs, and SF_6 made up the remaining 2% of 2019 CO_2e emissions. In 2005, CO_2 comprised 76% of the inventory and CH_4 19% of the inventory, with the remaining gases (N_2O, HFCs, PFCs, and SF_6) comprising the last 5% of the 2005 CO_2e emissions. Clearly, the percentage of Colorado's inventory resulting from CH_4 emissions has increased since 2005 relative to other GHGs, driven primarily by the growth in oil and natural gas production and decrease in emissions from the electric power sector. Overall, the CH_4 emissions trend is essentially flat from 2005 to 2019.

Exhibit ES 5: Estimated Colorado GHG Emissions by Gas 2005 - 2019 ($MMTCO_2e$)

Emissions (MMTCO2E)	2005	2010	2015	2019
CO_2				
Residential	7.613	7.851	7.502	7.951
Commercial	4.092	4.242	4.019	4.168
Industrial	12.849	14.232	14.319	15.305
Transportation	29.834	29.256	27.835	27.436
Electric Power	40.108	39.356	36.121	29.759
Industrial Processes	1.334	1.185	1.490	1.647
Total CO_2	95.830	96.122	91.286	86.266
CH_4				
Residential	0.069	0.077	0.076	NA
Commercial	0.018	0.020	0.020	NA
Industrial	0.008	0.008	0.009	NA
Transportation	0.069	0.050	0.048	NA
Electric Power	0.012	0.012	0.011	NA
Coal Mining	6.810	8.137	1.851	1.823
Natural Gas and Oil Systems	20.129	28.623	19.361	21.683
Agriculture	6.211	6.999	7.392	7.393
Land Use and Forestry	0.470	0.417	0.277	NA
Waste Management	2.224	3.433	4.020	4.227
Total CH4	36.021	47.775	33.065	35.126
N2O				
Residential	0.014	0.015	0.015	NA
Commercial	0.005	0.007	0.006	NA
Industrial	0.013	0.013	0.014	NA
Transportation	0.884	0.459	0.285	NA
Electric Power	0.171	0.168	0.151	NA
Agriculture	3.370	3.069	3.267	3.268
Land Use and Forestry	0.140	0.141	0.116	NA
Waste Management	0.142	0.150	0.167	0.176
Total N2O	4.739	4.022	4.021	3.444
HFC, PFC, and SF6				
Industrial Processes	1.820	2.490	3.018	3.009
GRAND TOTAL	138.410	150.410	131.390	127.845

Exhibit ES 6: Projected Colorado GHG Emissions by Gas 2020 - 2050 ($MMTCO_2e$)

	2020	2025	2030	2035	2040	2045	2050
CO_2	77.3	65.0	43.7	28.4	16.4	8.2	1.9
CH_4	34.0	27.9	18.6	16.4	14.2	11.9	9.7
N_2O	3.4	3.1	2.3	1.8	1.2	0.7	0.2
HFC, PFC, SF_6	4.7	4.0	2.9	2.6	2.2	1.7	1.1

The SIT model also looks at emissions intensity on a per capita and economic productivity basis as shown in Exhibit ES-7, which was also estimated for 2019 based on the Reference Scenario. Estimated GHG emissions per capita in Colorado have decreased since 2005 despite an increase in population. Furthermore, GHG emissions relative to gross state product have declined considerably since 2005 falling by 48% by 2019.

Exhibit ES 7: Estimated Colorado GHG Emissions per Capita and per Gross State Product 2005 - 2019 ($MTCO_2e$)

Emissions Per Capita & Gross State Product	2005	2010	2015	2019
State Population (thousands)	4,663	5,049	5,449	5,759
Emissions per Capita ($MTCO_2e$)	29.552	29.680	23.987	22.199
Emissions per Gross State Product ($MTCO_2e$/$ Million)	634.062	594.568	417.156	327.567

Finally, this inventory provides a comparison of emissions calculated using AR4 and AR5 GWP values in both 100-year and 20-year time horizons. Any comparison of projected emissions using different GWP values must also recalculate the 2005 baseline using the same factors for consistency.

Exhibit ES-8 provides a comparison of Colorado's 2005 GHG baseline emissions when calculated using 20-year and 100-year time horizon GWP values from the IPCC AR4 and AR5 reports. Exhibit ES-9 shows projected emissions reduction percentages from 2005 for the various GWP values.

Exhibit ES 8: Estimated 2005 Baseline GHG Emissions using AR4 and AR5 ($MMTCO_2e$)

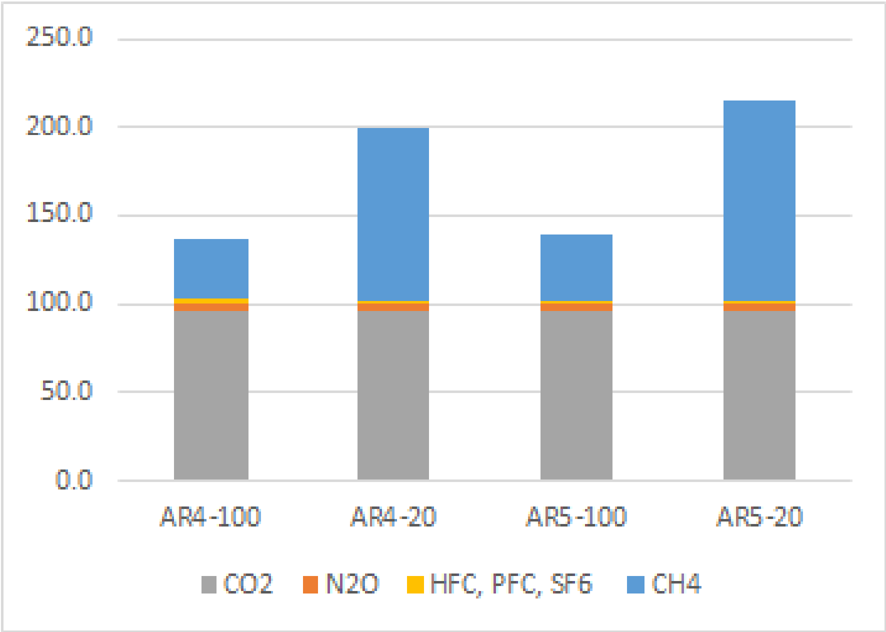
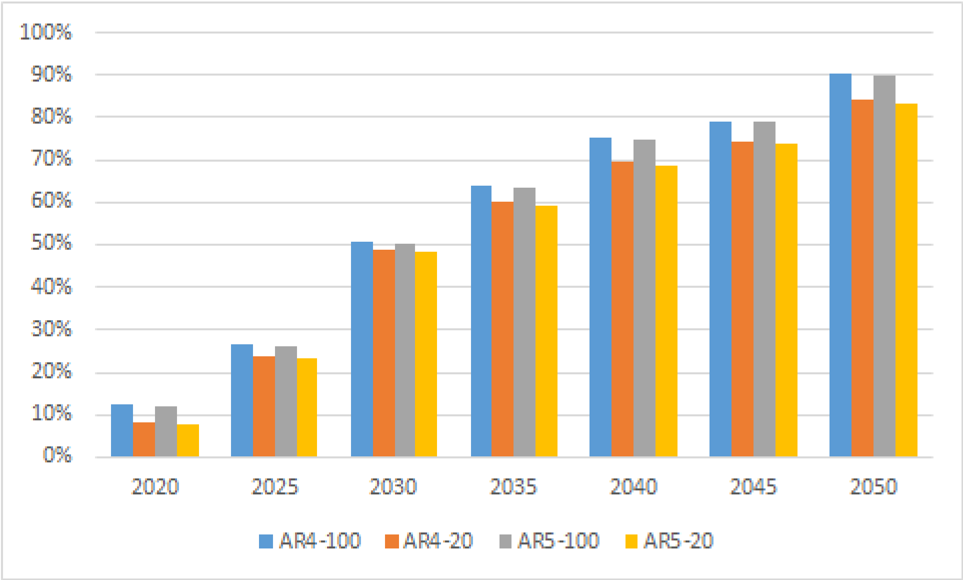


Exhibit ES 9: GHG Percent Reduction from 2005 Baseline using AR4 and AR5



The 2021 Colorado GHG Inventory shows a continued decline in total GHG emissions consistent with the previous publications by the Division. More importantly, this inventory represents a critical milestone in the transition of GHG data reporting and planning within Colorado necessary to achieve the goals set by the legislature in HB 1261. This inventory now also includes more detailed and Colorado specific modeling to project future emissions that are expected to be achieved as economy-wide GHG reduction strategies are implemented. By not relying exclusively on current "Business as Usual" projections, it facilitates active conversations and planning to achieve deep GHG reductions throughout the entire economy. It also provides a compliance trajectory by which progress can be assessed as GHG reduction strategies are implemented and additional detailed emissions data is reported under Regulation 22, Part A, approved by the AQCC in May 2020.

1. HISTORIC EMISSIONS OVERVIEW

1.1. Background

The EPA State Inventory Tool (SIT) model was used to generate a five-year update to the Colorado greenhouse gas (GHG) inventory in 2019 in accordance with Executive Order #D-004-08, issued April 22, 2008 by then-Governor Bill Ritter, Jr. That inventory includes estimates of historic GHG emissions from 1990 to 2015, the latest year for which activity data was consistently available at the time. This inventory updates the 2019 inventory by adding in revised oil and gas production emissions based on the Division's own analysis, as well as 2019-year emissions based on analyses conducted for the GHG Roadmap. The 2021 inventory also only dates back to 2005, because that is the baseline year used for comparing emissions reductions over time under Colorado law (see HB 1261/§25-7-102(g), C.R.S.), and includes updated projections for 2020 to 2050 from the GHG Roadmap. In accordance with international practice, emissions are reported in million metric tons (MMT) of carbon dioxide (CO_2) or carbon dioxide equivalent (CO_2e).

Emissions of methane (CH_4), nitrous oxide (N_2O), and various fluorinated compounds are converted to CO_2e by applying standard global warming potential (GWP) factors. Warming potential is a way to compare the climate change impact of different gases. It reflects how long a specific gas is likely to remain in the atmosphere and how strongly it absorbs energy. CO_2 is used as the reference gas, with the warming potential of other gases expressed as an equivalent quantity of CO_2. GWP factors have been calculated based on several different time horizons, including 20, 100, and 500 years. The GWP factors used for this inventory are the 100-year time horizon GWP factors taken from the IPCC Fourth Assessment Report.[5] For CH_4 this was a factor of 25 and for N_2O it was a factor of 298. The GWP factors for multiple time horizons were updated in the IPCC Fifth Assessment Report[6] and this is discussed in chapter 12. However, EPA mandates the use of the 100-year factors from the Fourth Assessment Report in the Greenhouse Gas Reporting Program (GHGRP).[7] The Colorado 2021 inventory update uses these factors to maintain consistency with EPA and other states' reporting programs.

[5] IPCC AR4 WG1 (2007), Solomon, S.; Qin, D.; Manning, M.; Chen, Z.; Marquis, M.; Averyt, K.B.; Tignor, M.; Miller, H.L.,eds.; Climate Change 2007: The Physical Science Basis, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press.

[6] IPCC AR5 WG1 (2013), Stocker, T.; Qin, D.;Plattner, G.; Tignor, M.; Allen, S.;Boschung, J.; Nauels, A.; Xia, Y.; Bex, V.; Midgley, P., eds.; Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on climate Change, Cambridge University Press.

[7] 40 CFR 98

1.2. State Inventory Tool

The SIT is a spreadsheet-based model, organized as a series of separate modules. These modules are each run independently to estimate Colorado GHG emissions by category (except for natural gas and oil production, which is based on the Division's analysis). Some modules estimate emissions from multiple sectors and some sectors are characterized using output from multiple modules. A Synthesis Tool consolidates the output from the individual modules. The User's Guide for each module describes the basis for the estimation methodology and the sources of default activity data and emission factors included in the module.

Each User's Guide includes a brief discussion of the history and philosophy of the SIT model. The model was developed to assist states in producing their own GHG inventories using standardized processes consistent with international methods. The estimation methods in the model have roots in the *State Workbook for Estimating Greenhouse Gas Emissions* (State Workbook). This process was modified and updated after 1998 to comport with the EPA's *Emissions Inventory Improvement Process for Criteria Pollutants* (EIIP). Volume VIII of the EIIP guidance, which covers greenhouse gas emissions, was last updated in 2004. The State Workb*ook*, and later the EIIP guidance, provided a detailed methodology for estimating GHG emissions but required considerable state time and resources. The SIT model automates this process, while still allowing states to use more accurate state-level data if it is available. SIT methodologies are consistent with those used in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*.[8]

Each module in the tool provides default activity data, most linked to national databases created from various sources. Most of these data sources have their origins in state and federal reporting requirements. Data sources include reports from federal agencies and industry organizations. Much of the data in these reports is provided by individual sources, then aggregated to a single state-wide value. The source of default data for each module is listed in the User's Guide for that module and sometimes on one or more worksheets in the module itself.

The individual SIT modules are periodically updated and made available on the EPA website. The website provides only the most current modules and User's Guides.[9] Please refer to Exhibit 1-1 in the 2019 GHG inventory report[10] for the specific modules and User's Guides used for that inventory, which remain the same for this inventory except for the LULUCF module and user guide that is from the October 2020 SIT update.

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[8] U.S. EPA User's Guide for Estimating Direct Carbon Dioxide Emissions from Fossil Fuel Combustion Using the State Inventory Tool (October 2017).

[9] https://www.epa.gov/statelocalenergy/download-state-inventory-and-projection-tool

[10] See 2019 Colorado Greenhouse Gas Inventory report at https://www.colorado.gov/pacific/cdphe/colorado-greenhouse-gas-reports

All SIT model modules were run using the EPA-provided default input data, emission factors, and GWP factors, with the exception of the addition of state-specific data on acres burned by wildfire each year in the LULUCF module. In areas where an activity does not occur in Colorado or the SIT does not include default data for a Colorado source sector, the model generates a zero emission profile. This includes a few cases where default data is generally available, but is missing for certain activities in one or more years. A blank field in a data table indicates a lack of activity data for that category in that year.

For space and appearance purposes and to maintain consistency with prior inventories, tables in this inventory include emissions estimates at 5-year intervals since 2005, plus year 2019 (not based on SIT), and do not include categories that had zero emissions in Colorado (e.g., cable cars, trolleys, etc.) or for which insufficient data was available. Chapters 3 through 11 include more detailed information on individual sectors covered in this inventory, most of which remains unchanged from the 2019 inventory. Please refer to Exhibit 1-2 in the 2019 GHG inventory report for the SIT modules used to estimate emissions or sinks from each sector.[11] As previously noted, the SIT Natural Gas and Oil Systems module is not relied on for this inventory; rather, emissions from natural gas and oil systems are based on the Division's own analysis of GHG emissions from this sector.

1.3. Natural Gas and Oil Production Emissions

Due to the limitations and uncertainties of the SIT and to account for multiple regulatory initiatives undertaken by the state of Colorado since 2005 to address oil and gas emissions, along with other factors noted below, the Division conducted a detailed analysis to provide a more refined estimate of natural gas and oil production emissions in Colorado for use in the GHG Roadmap and this inventory.

To assess natural gas and oil production emissions from 2005 and on, the Division's analysis used a combination of state-level inventory data, production data from the Colorado Oil and Gas Conservation Commission (COGCC), type of well drilled (vertical vs horizontal), engineering design analyses such as stages of separation and use of tankless systems at well production facilities, natural gas sampling analyses from around the state, estimates of flaring and venting rates, assumed capture and control efficiencies for emissions, regulatory reach and effectiveness for adopted rules, and top-down flyover studies of methane in oil and gas basins conducted in Colorado and elsewhere.

The Division believes that its analysis provides a more accurate assessment of natural gas and oil production emissions than the SIT. The SIT relies on a broad and generalized approach to estimating emissions that is not specific to Colorado and does

[11] See 2019 Colorado Greenhouse Gas Inventory report at https://www.colorado.gov/pacific/cdphe/colorado-greenhouse-gas-reports

not account for differing emission rates based on specific activities, specific types and quantities of equipment, actual rates of production, and regional differences in oil and gas characteristics. For example, for natural gas wells, the SIT estimates emissions using the number of producing gas wells in the state, but not actual production from those wells, and a regional emission factor per well that applies to all wells in the Rocky Mountain region states.[12] For oil wells, the SIT uses a national emission factor. Additionally, the SIT does not account for regulatory actions to reduce oil and gas emissions, which the state of Colorado has undertaken numerous times since 2005.

The Division's analysis, however, does result in a greater amount of GHG emissions from natural gas and oil production than the SIT. For example, the SIT estimates emissions of 8.083 MMTCO2e in 2005[13] while the Division's analysis estimates emissions of 20.166 MMTCO2e that year. And for 2015, the SIT estimates emissions of 15.619 MMTCO2e while the Division's analysis results in emissions of 19.648 MMTCO2e. The higher numbers are primarily the result of estimated leak rates and measurements of CH_4 from flyover studies, which are not accounted for in the SIT. The Division's analysis of natural gas and oil production emissions in Colorado, including leak rates, is discussed in more detail in Chapter 8.

1.4. 2019-Year Emissions from GHG Roadmap

As previously noted, Colorado's GHG emissions from 2005 – 2015 were estimated using the EPA SIT model. However, for year 2019 emissions, Colorado relied on analysis completed for the GHG Roadmap under what is known as the "Reference Scenario", which accounts for policies and measures taken prior to 2019 to reduce GHG emissions. These include adoption of a RPS for electricity generation, fuel switching from coal to natural gas for electricity generation, and rules to address methane emissions from the oil and gas industry. Please note that emissions from natural gas and oil systems for 2019 in the inventory differ from the Reference Scenario due to updated data and additional analysis done for this sector by the Division.

Exhibit 1-1 shows the percentage of GHG emissions by sector in 2019. The majority of emissions come from the electric power, transportation, and the residential, commercial and industrial fuel use sectors, followed by natural gas and oil systems and agriculture. The remaining emissions are split between industrial processes, waste management, and coal mining and abandoned mines.

[12] Arizona, Colorado, Idaho, Montana, Nevada, North Dakota, South Dakota, Utah, and Wyoming

[13] See Exhibit 8-1 in 2019 Colorado Greenhouse Gas Inventory report at https://www.colorado.gov/pacific/cdphe/colorado-greenhouse-gas-reports

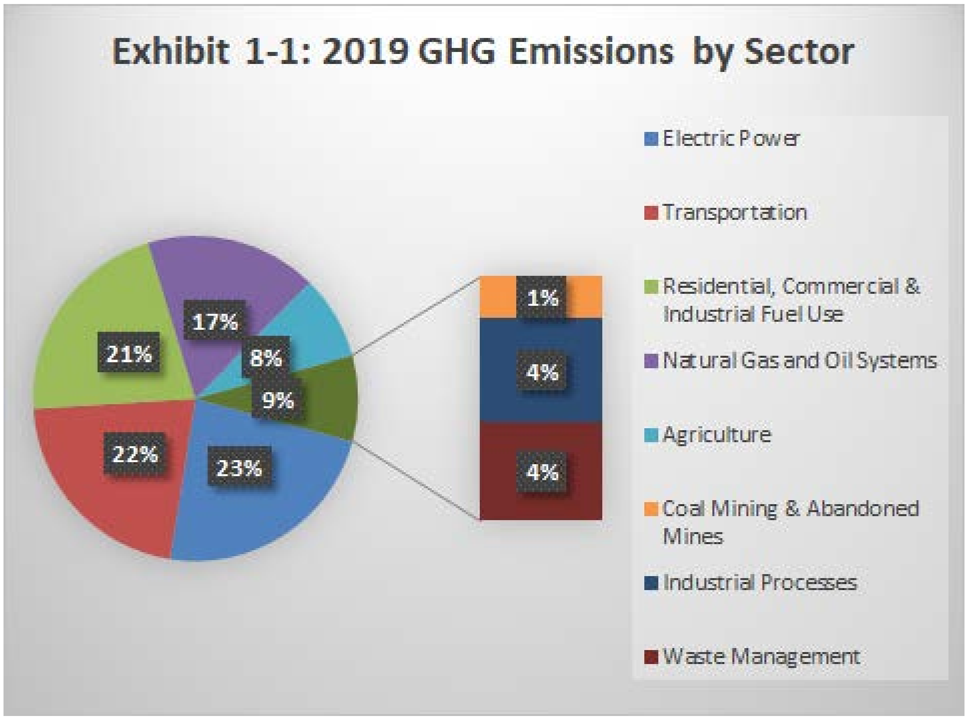


Exhibit 1-1: 2019 GHG Emissions by Sector

1.5. Summary of Colorado GHG Emissions

The following Exhibits provide a comprehensive summary of Colorado GHG emissions, as estimated using the EPA SIT model, the Division's analysis of oil and natural gas production emissions, and analysis conducted for the GHG Roadmap for 2019-year emissions. Note that 2019-year emissions from the Reference Scenario in the GHG Roadmap may differ from SIT model estimates for prior years. For example, the Reference Scenario did not estimate emissions from Land Use and Forestry, which the SIT model performs although the model is only current through 2018 for historic emissions. The Reference Scenario also did not estimate indirect CO_2 emissions from electricity consumption, which the SIT model also performs.

Emissions are organized by sector, which for some sectors includes summing information from multiple SIT modules. Exhibits 1-2 and 1-3 provide an overview of state GHG emissions by sector. Exhibits 1-4 and 1-5 provide the same overview organized by gas, and Exhibit 1-6 by gas intensity per capita and relative to gross state product. Numbers may differ slightly between tables due to rounding difference.

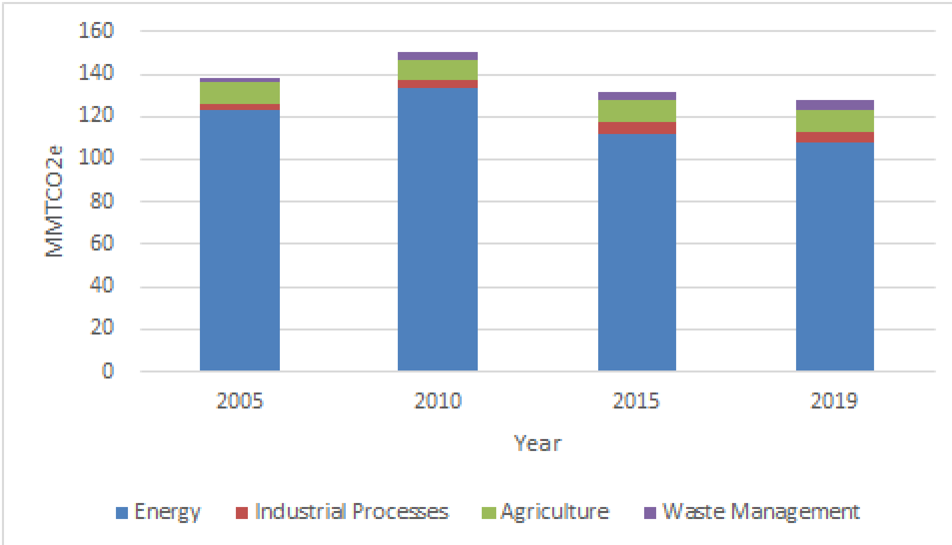
Exhibit 1-2: Summary of Estimated Colorado GHG Emissions by Sector

Emissions (MMTCO$_2$E)	2005	2010	2015	2019
Energy				
Residential	7.696	7.943	7.593	7.951
Commercial	4.115	4.269	4.045	4.168
Industrial	12.833	13.978	14.055	15.058
Transportation	30.787	29.764	28.168	27.436
Electric Power	40.291	39.535	36.283	29.759
Coal Mining	6.810	8.137	1.851	1.823
Natural Gas and Oil Systems	20.166	28.899	19.648	21.930
Total Energy	**122.698**	**132.525**	**111.643**	**108.125**
Industrial Processes				
Total Industrial Processes	**3.154**	**3.675**	**4.508**	**4.656**
Agriculture				
Enteric Fermentation	5.314	5.957	6.187	6.187
Manure Management	1.497	1.623	1.843	1.844
Agricultural Soil Management	2.768	2.482	2.625	2.625
Burning of Agricultural Crop Waste	0.003	0.006	0.005	0.005
Total Agriculture	**9.582**	**10.069**	**10.660**	**10.661**
Waste Management				
Municipal Solid Waste	1.797	2.964	3.519	3.701
Wastewater	0.568	0.619	0.668	0.702
Total Waste Management	**2.366**	**3.583**	**4.186**	**4.403**
GRAND TOTAL CO$_2$e	**137.800**	**149.852**	**130.997**	**127.845**
Land Use & Forestry (LULUCF)	4.310	6.450	7.460	NA
TOTAL CO2e (including LULUCF)	**142.110**	**156.302**	**138.457**	**127.845**
Indirect CO2 from Electricity Consumption*	44.282	47.076	39.477	NA

* Emissions from Electricity Consumption are not included in totals to avoid double counting with fossil fuel combustion estimates.

The distribution of estimated GHG emission by sector is shown in Exhibit 1-4 below. The majority of GHG emissions in Colorado are from the Energy sector. This includes fossil fuels burned to generate electricity, burned for transportation, and those burned in residential, commercial, and industrial heating applications, as well emissions from oil and natural gas production. Emissions from this sector comprised approximately 89% of the total GHG inventory (minus LULUCF) in 2005 and 85% of the inventory in 2019. The next largest source of GHGs is the Agriculture sector, contributing approximately 7% of the inventory in 2005 and 8% in 2019. Waste management and industrial processes make up the remainder of the inventory at 4% in 2005 and 7% in 2019.

Exhibit 1-3: Estimated Colorado GHG Emissions by Sector



Exhibits 1-4 and 1-5 show the distribution of Colorado's GHG emissions by specific gas. The data in Exhibit 1-5 shows a significant decrease in CH_4 emissions from the Coal Mining sector between 2010 and 2019. This is due to a decrease in coal mined in Colorado, and is discussed in more detail in Chapter 7. The table in Exhibit 1-5 includes emissions from the Land Use and Forestry sector in 2005, 2010, and 2015, which includes emissions resulting from wildland fires. Note that CO_2 released from the burning of biomass is considered carbon neutral and is not included in the inventory.

Exhibit 1-4: Estimated 2019 Colorado GHG Emissions by Gas

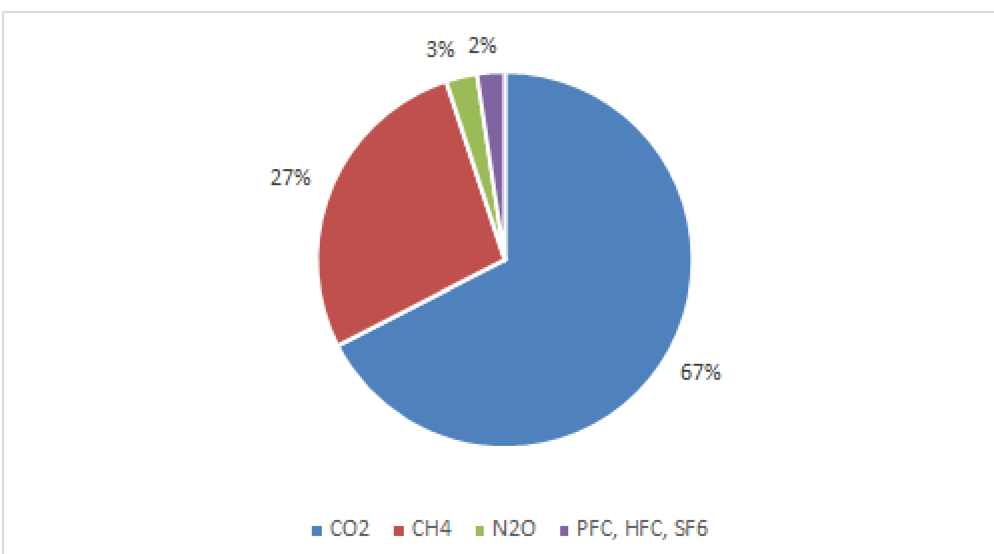


Exhibit 1-5: Summary of Estimated Colorado GHG Emissions by Gas

Emissions (MMTCO2E)	2005	2010	2015	2019
CO_2				
Residential	7.613	7.851	7.502	7.951
Commercial	4.092	4.242	4.019	4.168
Industrial	12.849	14.232	14.319	15.305
Transportation	29.834	29.256	27.835	27.436
Electric Power	40.108	39.356	36.121	29.759
Industrial Processes	1.334	1.185	1.490	1.647
Total CO_2	95.830	96.122	91.286	86.266
CH_4				
Residential	0.069	0.077	0.076	NA
Commercial	0.018	0.020	0.020	NA
Industrial	0.008	0.008	0.009	NA
Transportation	0.069	0.050	0.048	NA
Electric Power	0.012	0.012	0.011	NA
Coal Mining	6.810	8.137	1.851	1.823
Natural Gas and Oil Systems	20.129	28.623	19.361	21.683
Agriculture	6.211	6.999	7.392	7.393
Land Use and Forestry	0.470	0.417	0.277	NA
Waste Management	2.224	3.433	4.020	4.227
Total CH4	36.021	47.775	33.065	35.126
N2O				
Residential	0.014	0.015	0.015	NA
Commercial	0.005	0.007	0.006	NA
Industrial	0.013	0.013	0.014	NA
Transportation	0.884	0.459	0.285	NA
Electric Power	0.171	0.168	0.151	NA
Agriculture	3.370	3.069	3.267	3.268
Land Use and Forestry	0.140	0.141	0.116	NA
Waste Management	0.142	0.150	0.167	0.176
Total N2O	4.739	4.022	4.021	3.444
HFC, PFC, and SF6				
Industrial Processes	1.820	2.490	3.018	3.009
GRAND TOTAL	138.410	150.410	131.390	127.845

Exhibit 1-6 shows emissions per year expressed on a per capita and Gross State Product (GSP) basis. Note that this is based on total emissions because gross and net emissions are the same due to the LULUCF sector now being considered a source of emissions rather than a sink based on recent updates to the SIT model (see "Land Use and Forestry" section). Despite growth in population and GSP since 2005, the intensity of emissions per person and per gross state product has decreased. From 2005 to 2019, population increased by 24% but GHG emissions per capita decreased by approximately 25%. In that same period, gross state product increased by nearly 80%, but emissions per dollar generated decreased by 48%.

Exhibit 1-6: Colorado GHG Emissions Summary by Intensity

Emissions Per Capita (MTCO2E)	2005	2010	2015	2019
State Population (thousands)	4,663	5,049	5,449	5,759
Emissions Intensity	29.552	29.680	23.987	22.199
Emissions Per Gross State Product (MTCO2E)	**2005**	**2010**	**2015**	**2019**
Gross State Product (Billion $)	217.329	252.035	313.329	390.283
Emissions Intensity	634.062	594.568	417.156	327.567

Exhibits 1-7 and 1-8 further demonstrate how per capita GHG emissions relative to state population and GHG emissions relative to GSP have changed over time. As noted, per capita emissions have decreased significantly since 2010 while population continues to rise.

Exhibit 1-7: Population vs. Estimated GHG Emissions per Capita

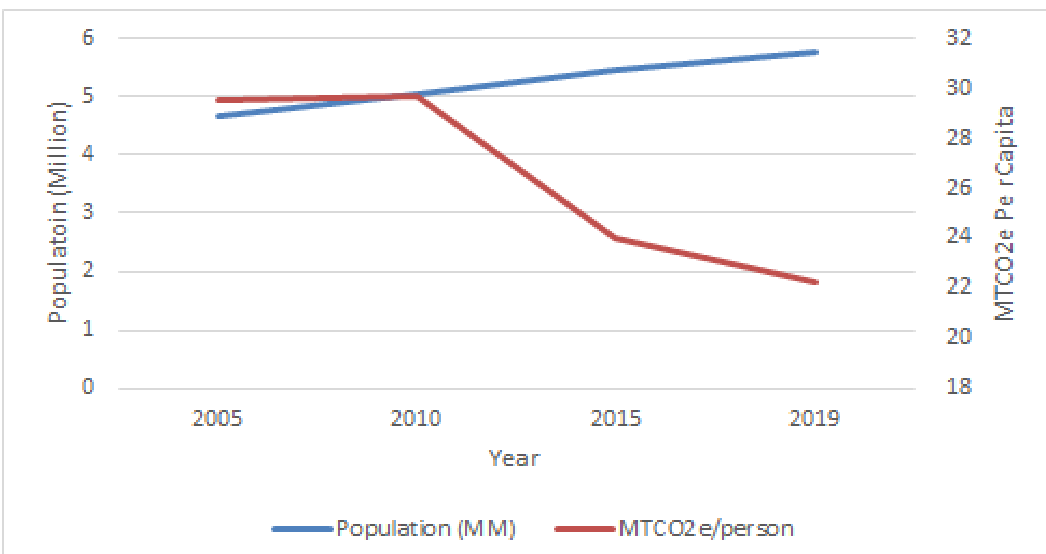
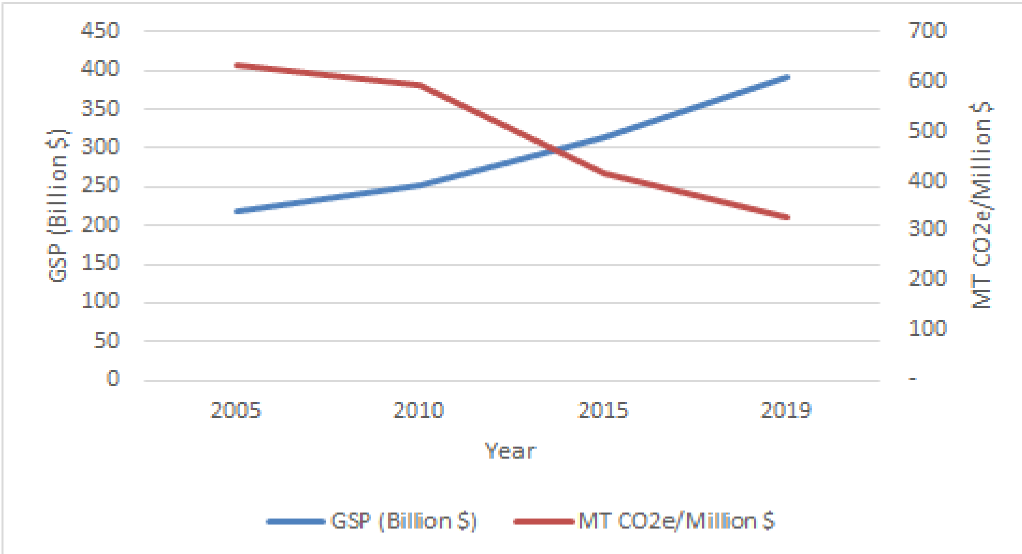


Exhibit 1-8: Estimated Gross GHG Emissions vs. Gross State Product



1.6. Colorado Trends

The primary gas in the inventory is CO_2, which is directly emitted from the combustion of all forms of fossil fuels. Greenhouse gases, including CO_2, CH_4, and N_2O, generated from fossil fuel production and combustion accounted for approximately 85% of the state inventory in 2019 and include a combination of emissions from electrical power production, transportation fuel use, and the use of fossil fuels in residential, commercial and industrial heating applications. Source categories which produce and/or burn fossil fuels have been grouped together into an "Energy" sector. Within this sector, the largest sources of emissions are electricity generation, transportation, and natural gas and oil systems accounting for nearly three-quarters of the sector's emissions and nearly two-thirds of the total inventory emissions in 2019. Exhibits 1-10 and 1-11 show the distribution of emissions within the Energy sector in 2005 and in 2019. The sector's total emissions have decreased by approximately 12% during that time. Additionally, between 2005 and 2019, the proportion of emissions from electricity generation and coal mining decreased while the proportion from natural gas and oil systems and residential/commercial/industrial fuel use increased.

Exhibit 1-9: 2005 Estimated Energy Sector GHG Emissions by Category

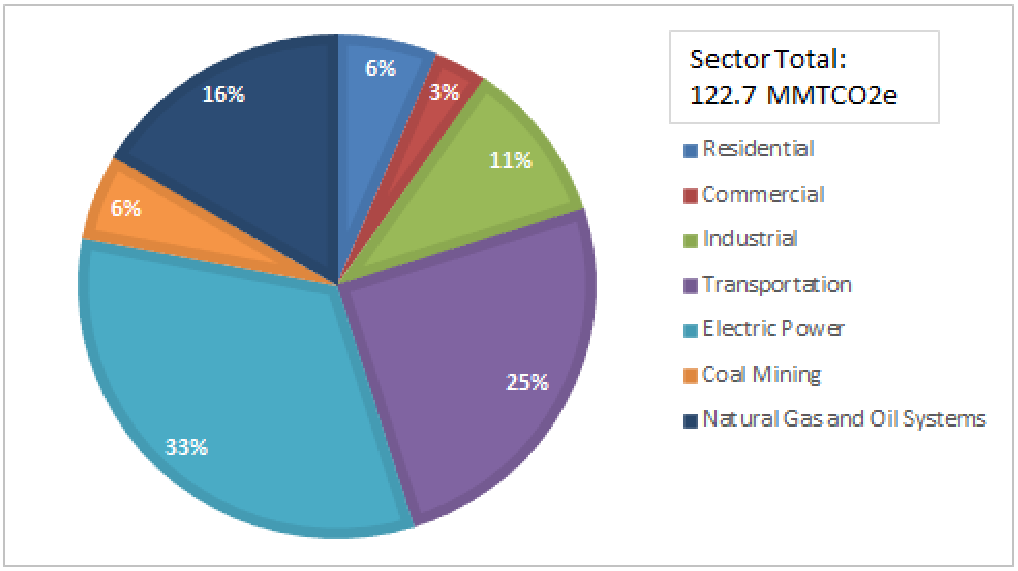
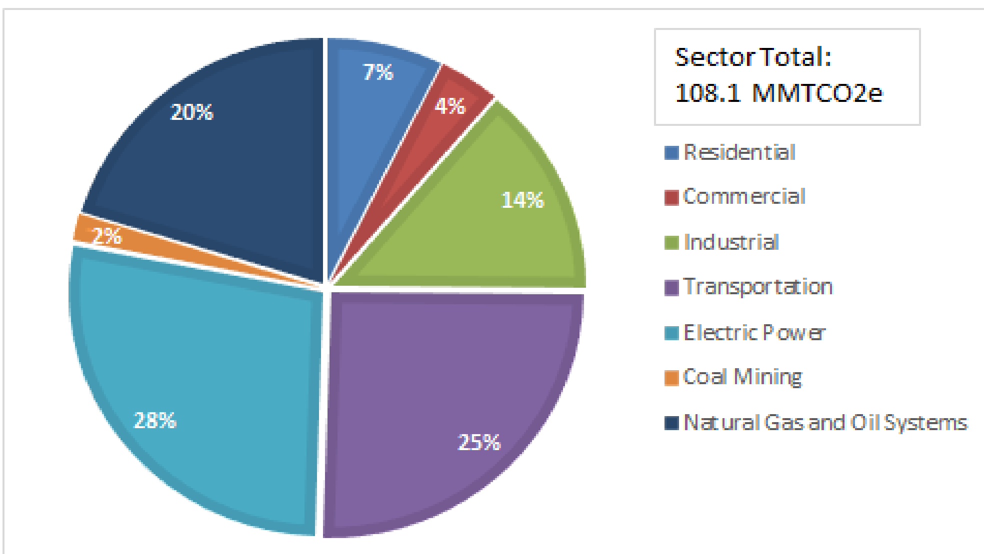


Exhibit 1-10: 2019 Estimated Energy Sector GHG Emissions by Category



The Energy sector's Industrial emissions result from the combustion of fossil fuels and include applications such as heating and engines that run equipment. The Transportation category includes emissions from automobiles, aircraft, and diesel on- and off-road mobile sources, including farm equipment, trains and boats.

Coal mining emissions are primarily from CH_4 released in the process of exposing coal to the atmosphere. These emissions are direct emissions from underground mines, abandoned mines, and emissions related to mining activities such as crushing, loading and transporting coal.

Methane leaks are a source of GHG emissions that can occur throughout the natural gas and oil production process. In 2005, natural gas and oil production accounted for about 16% of the state's GHG emissions. Based on the Division's analysis (see Section 1.3), this has increased to 17% in 2019 due to an overall increase in oil and natural gas production in the state. The Division's analysis of natural gas and oil production emissions in Colorado, including leak rates, is discussed in more detail in Chapter 8.

As a point of clarification, the Industrial Process sector is distinctly different from the Industrial category of the Energy sector. The Industrial Process sector includes non-combustion GHG emissions resulting from manufacturing products such as cement, lime, soda ash, iron and steel, ammonia, aluminum, and nitric acid. The sector also includes leakage of substitutes for ozone depleting substances, such as hydrofluorocarbons (HFCs).

Agricultural sector sources include a combination of emissions from waste material decomposition, soil management, agricultural burning, livestock enteric fermentation (flatulence), and manure management. The Waste Management sector includes emissions of CH_4 from landfills, and CH_4 and N_2O from wastewater treatment. CH_4 is generated from the decomposition of organic materials in landfills. The disposal and treatment of municipal and industrial wastewater results in CH_4 emissions from digesters using either aerobic or anaerobic methods. Nitrogen-rich organic matter also produces nitrous oxide via natural nitrification/denitrification processes.

Individual sectors are discussed in more detail in Chapters 3 through 11.

1.7. Comparison to 2019 GHG Inventory

The most recent Colorado GHG inventory prior to this one was completed in 2019 using the 2017 version of the SIT model, and includes emissions estimates from 1990 through 2015 and projections to 2030.[14] The SIT model is not static, but is periodically updated and revised to account for improved calculation methods, changes in emission factors and global warming potentials, and improvements in the availability and quality of input data. In late October 2020, EPA released an update to the SIT to include activity data through 2018,[15] which also includes updates or changes to certain modules in terms of how emissions are calculated. For example, forest carbon flux calculations were updated in the LULUCF module, which is discussed in more detail in chapter 11. The updated LULUCF module calculations have been incorporated into this inventory, which shows LULUCF to now be a source of emissions rather than a sink as shown in the 2019 inventory. However, the LULUCF

[14] Colorado Department of Public Health & Environment. Colorado 2015 Greenhouse Gas Inventory Update Including Projections to 2020 & 2030 by Sara Heald, December 2019.

[15] https://www.epa.gov/statelocalenergy/download-state-inventory-and-projection-tool

emissions are kept separate from the total emissions in the inventory because LULUCF emissions are predominantly non-anthropogenic sources of emissions. The Division will continue to evaluate updates to the other SIT modules for possible incorporation into the inventory before it is finalized later in 2021, but at this time much of this current inventory, which is based on the SIT, is unchanged from the 2019 inventory.

There are, however, a few but significant differences in this inventory as compared to the 2019 inventory beyond the change regarding LULUCF emissions. Most notably, this inventory includes 2019-year emissions and updated oil and gas production emissions that are not based on the SIT. The update to the LULUCF and oil and gas emissions affects some of the historic analyses in the two inventories, such as per capita emissions and emissions per gross state product.

Exhibits 1-11 and 1-12 show historic GHG emissions by sector in the 2019 and 2021 inventory reports. As noted, the 2019 inventory only has historic emissions through 2015.

Exhibit 1-11: 2019 GHG Inventory Report, Emissions by Sector 2005 - 2015

Emissions by Sector ($MMTCO_2e$)	2005	2010	2015
Electric Power	40.291	39.535	36.283
Transportation	30.787	29.764	28.168
Residential, Commercial & Industrial Fuel Use	24.643	26.190	25.692
Natural Gas and Oil Systems*	8.083	12.045	15.619
Agriculture	9.582	10.069	10.660
Coal Mining & Abandoned Mines	6.810	8.137	1.851
Industrial Processes	3.154	3.675	4.508
Waste Management	2.366	3.583	4.186
Grand Total	125.716	132.998	126.967

Exhibit 1-12: 2021 GHG Inventory Report, Emissions by Sector 2005 - 2019

Emissions ($MMTCO_2E$)	2005	2010	2015	2019
Energy				
Residential	7.696	7.943	7.593	7.951
Commercial	4.115	4.269	4.045	4.168
Industrial	12.833	13.978	14.055	15.058
Transportation	30.787	29.764	28.168	27.436
Electric Power	40.291	39.535	36.283	29.759
Coal Mining	6.810	8.137	1.851	1.823
Natural Gas and Oil Systems	20.166	28.899	19.648	21.930
Total Energy	122.698	132.525	111.643	108.125
Industrial Processes				
Total Industrial Processes	3.154	3.675	4.508	4.656
Agriculture				
Enteric Fermentation	5.314	5.957	6.187	6.187
Manure Management	1.497	1.623	1.843	1.844
Agricultural Soil Management	2.768	2.482	2.625	2.625
Burning of Agricultural Crop Waste	0.003	0.006	0.005	0.005
Total Agriculture	9.582	10.069	10.660	10.661
Waste Management				
Municipal Solid Waste	1.797	2.964	3.519	3.701
Wastewater	0.568	0.619	0.668	0.702
Total Waste Management	2.366	3.583	4.186	4.403
GRAND TOTAL CO_2e	137.800	149.852	130.997	127.845
Land Use & Forestry (LULUCF)	4.310	6.450	7.460	NA
TOTAL CO2e (including LULUCF)	142.110	156.302	138.457	127.845

2. PROJECTIONS

2.1. Background

This section is a completely revised section from the 2019 inventory due to the change in methodology from using the SIT projections to using the Pathways model with underlying LEAP software from the Stockholm Environmental Institute. This section is focused on continued efforts to achieve the HB 1261 targets. It is being shortened considerably for this inventory report through reference to the work performed for the GHG Roadmap and technical data published in support of that project on the Colorado Energy Office (CEO) website. It would be expected to expand in size in the next inventory when all of the projection modeling would be done in-house.

The most significant difference between this inventory as compared to the 2019 inventory are in the projections. While the SIT Projection Tool may assist in looking at trends over the long term, there are some significant uncertainties and limitations associated with using it. While Colorado-specific data can be included in calculating historic emissions using the SIT, there are limited provisions for state adjustments to activity data and no ability for state-specific adjustments to emission factors to account for adopted and planned GHG reduction strategies in the future projections. As specific examples, within the electricity generation, transportation, industrial processes (HFCs), and oil and gas production sectors, Colorado has adopted emission control strategies or requirements that go beyond what is included in the SIT Projection Tool, which generally uses national data to project emissions and apportions emissions back to the state based on population or historical activity.

Projection of emissions from 2020 to 2050 is an important element of this GHG inventory, particularly in regard to demonstrating the path that is anticipated to achieve the statutorily-mandated GHG reduction goals. Under HB 1261, mandated emission reductions are assessed against the baseline year emissions in 2005. This inventory establishes a trajectory that Colorado intends to pursue in order to achieve the GHG reductions goals.

In addition to providing updated projections, future bi-annual GHG inventories will provide the data to be able to assess the progress toward achieving the 2025, 2030, and 2050 goals and success of legislation, regulation, and policies enacted to reduce GHG emissions. Additionally, critical data elements are being identified to be made available on a public dashboard and discussed at annual briefings with the AQCC in order to continually monitor progress toward the reduction goals.

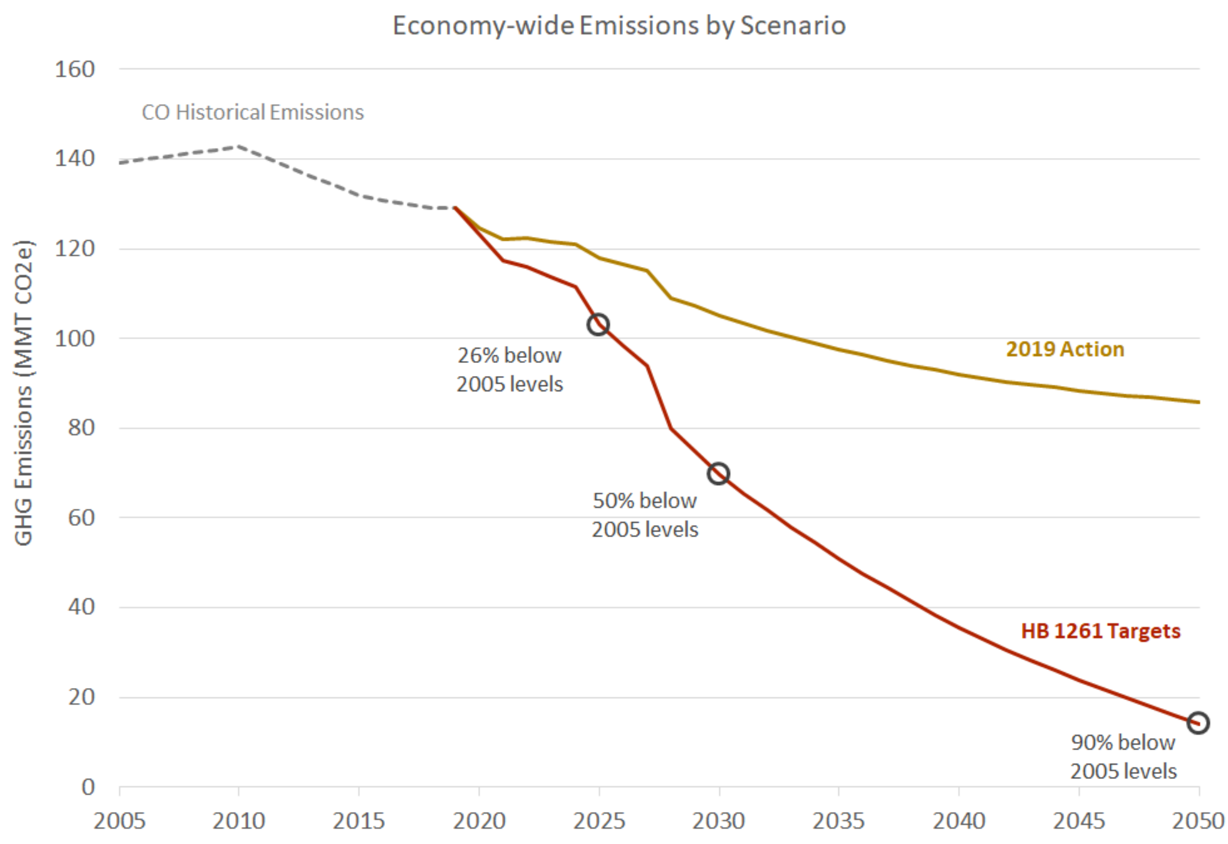
The projections in this inventory are based on the models developed and analysis completed for the state's GHG Roadmap project. The GHG Roadmap was a collaborative effort across multiple Colorado agencies, led by the Colorado Energy

Office, to define an emissions trajectory necessary to achieve Colorado's GHG reduction goals. The final GHG Roadmap is expected to be published in early 2021. Modeling was conducted for the GHG Roadmap using PATHWAYS and RESOLVE models by Energy and Environmental Economics (E3), a leading national consulting firm. E3 used its PATHWAYS model, which is built using bottom-up data for all emissions produced and energy consumed within the state, to simulate the emissions from all sectors and its RESOLVE model to develop least-cost electricity generation information for the Roadmap project. These models have been provided to the Division for future use.

Due to the limitations of the SIT Projection Tool, and its inability to be modified to account for recently enacted and anticipated GHG reduction strategies, Colorado is using a different methodology for projecting emissions beginning with this inventory and going forward. Performing the projection modeling using a Colorado specific model provides the opportunity for customization based on legislation, regulation, and policies adopted and proposed in Colorado as well as incorporation of state specific information including demographics, energy consumption, and emissions monitoring data as these factors evolve. Using a Colorado specific model for projections will also create the ability to estimate emissions using different sensitivity assumptions as Colorado continues to assess progress toward the HB 1261 goals. Colorado specific modeling will be further benefited by the AQCC's adoption of GHG reporting requirements for oil and gas in Regulation 7 and the comprehensive statewide GHG reporting rule adopted in Regulation 22 pursuant to SB 96. Reporting under these regulations will begin in early-to-mid-2021, and full reporting will begin in 2022.

An overview of the Roadmap 1261 Targets scenario, and the 2019 Action scenario which is included here as a reference for modeled emissions if no further actions were taken <u>after</u> 2019, are displayed in Exhibit 2-1.

Exhibit 2-1: Estimated Colorado Emissions through 2050 ($MMTCO_2e$)



Model assumptions and emissions output data files have been published as part of the GHG Roadmap project and can be located at:

https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap

The GHG Roadmap also incorporates the Division's recent work to quantify emissions reductions of various near term strategies through the Air Quality Control Commission (AQCC) GHG strategies subcommittee. Information regarding potential strategies, anticipated emissions reductions, and sector specific emissions targets are also included in the Roadmap and supporting documentation.

Because information and data is already publicly available, this supporting technical information has not been duplicated in this GHG Inventory report. Future GHG Inventories are expected to contain supporting technical documentation similar to that provided for the GHG Roadmap project once the Division begins performing the projection modeling activities.

Together, the E3 modeling and the Division's strategy development efforts combine to project emissions based on energy consumption trends considering existing and anticipated emissions reduction actions that are expected to be implemented within the next decade.

2.2. 2019 Action Scenario Model Projections

The 2019 Action Scenario in the GHG Roadmap evaluated projected emission reductions based on legislative and administrative actions taken by the state of Colorado prior to and during 2019. This projection shows that Colorado, with no additional policy, regulatory, or legislative measures would have been on a path to reduce emissions by approximately 16% in 2025 and 25% in 2030. The 2019 Action Scenario is provided within this report as a reference point. Since 2019 Colorado has implemented additional requirements and policies designed to further reduce GHG emissions and there are significant actions planned in 2021 and beyond to ensure the state is on the path to achieving the goals established in HB 1261.

2.3. HB 1261 Target Scenario Model Projections

The HB 1261 Target Scenario in the GHG Roadmap identifies one illustrative scenario of sectoral changes and the impacts of additional measures needed to reach the 2025 target of reducing GHG emissions by 26%, 2030 emissions by 50%, and 2050 emissions by 90% from 2005 levels. E3's analysis demonstrates that achieving Colorado's 2025 and 2030 GHG emissions targets is feasible with existing technologies, but will require additional measures in the coming years to achieve the goals. The changes needed to achieve the 2030 goals rely primarily on existing mature technologies while achieving the 2050 goals likely requires innovation to drive costs down and enable large scale deployment of technologies that are less mature.

2.4. AQCC GHG Strategy Subcommittee Efforts

During the course of the development of the GHG Roadmap, the Air Quality Control Commission, and other stakeholders, requested details on specific policies that Colorado might pursue to meet the HB 19-1261 GHG reduction targets in 2025 and 2030. As a result of these requests, the Division worked with other state agencies contributing to the GHG Roadmap to develop a list of possible near term strategies, quantify the potential emission reductions from implementation of these strategies, and develop appropriate targets for the electricity generation, oil and gas, transportation, and residential, commercial, and industrial fuel use sectors.

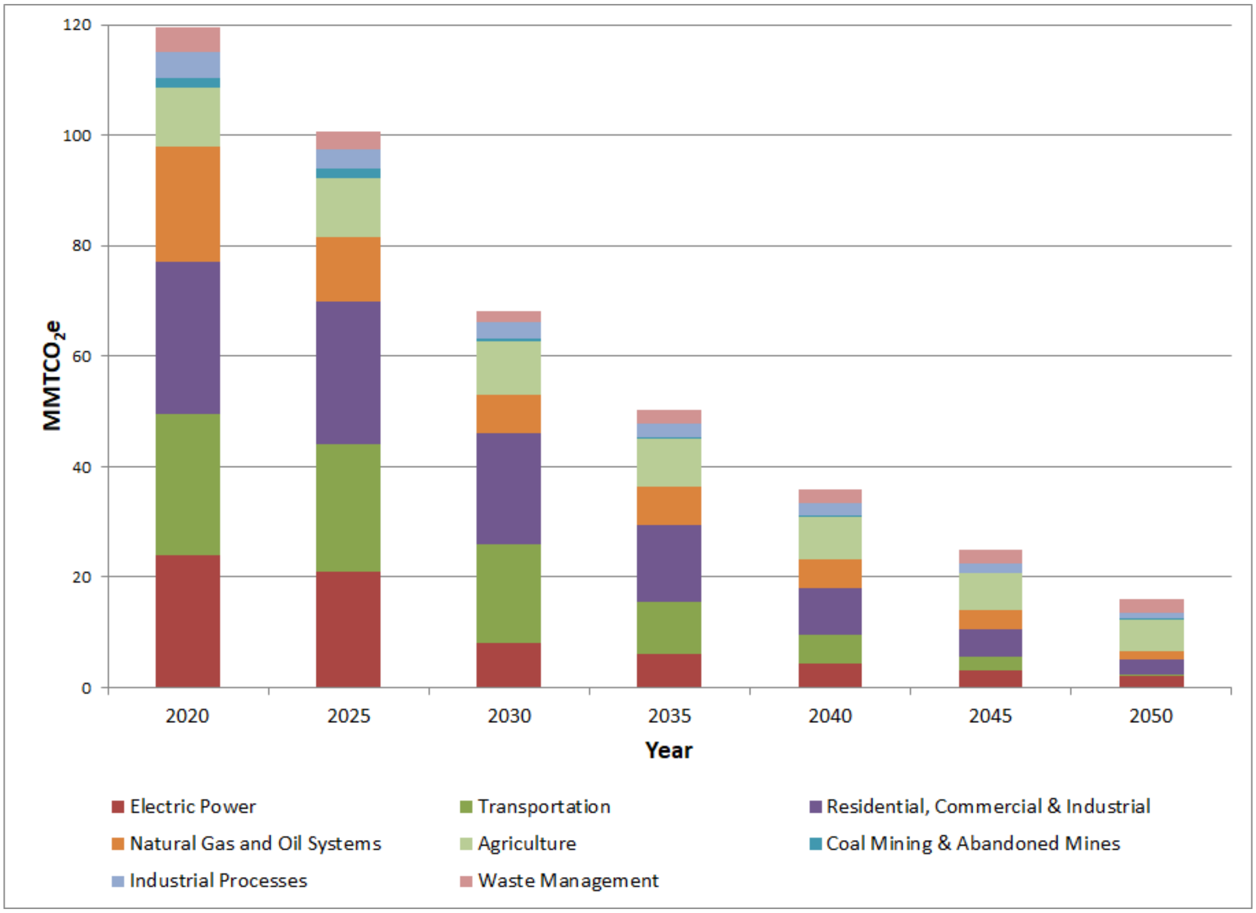
2.5. Emissions by Sector

The PATHWAYS model developed by E3 generates emissions results summarized by sector. The work performed by the Division for the AQCC GHG subcommittee was also organized by sector for consistency with the Roadmap work and past GHG Inventory reports. Exhibits 2-2 and 2-3 provide a summary of Colorado projected emissions from 2020 through 2050 that resulted from these efforts. Projected sector values for 2025 and 2030 align with the targets established by the AQCC GHG Strategies resolution after conversion from AR5 to AR4 GWPs. Projected values for 2035 through 2050 come from the 1261 Targets scenario model from the Colorado GHG Roadmap.

Exhibit 2-2: Projected Colorado Emissions by Sector 2020-2050 ($MMTCO_2e$)

Emissions by Sector ($MMTCO_2e$)	2020	2025	2030	2035	2040	2045	2050
Electric Power	24.039	21.000	8.000	6.177	4.295	3.243	2.192
Transportation	25.483	23.000	18.000	9.287	5.245	2.406	0.206
Residential, Commercial & Industrial Fuel Use	27.582	26.000	20.000	13.886	8.492	4.934	2.597
Natural Gas and Oil Systems*	20.767	11.600	7.100	7.109	5.259	3.409	1.559
Agriculture	10.661	10.641	9.673	8.588	7.639	6.690	5.741
Coal Mining & Abandoned Mines	1.819	1.786	0.536	0.197	0.188	0.180	0.173
Industrial Processes	4.694	3.500	2.900	2.602	2.206	1.695	1.057
Waste Management	4.459	3.072	2.031	2.412	2.436	2.454	2.463
Negative Emissions Technologies	0.000	0.000	0.000	-1.056	-1.744	-2.431	-3.119
Grand Total	119.504	100.598	68.241	49.200	34.015	22.579	12.869

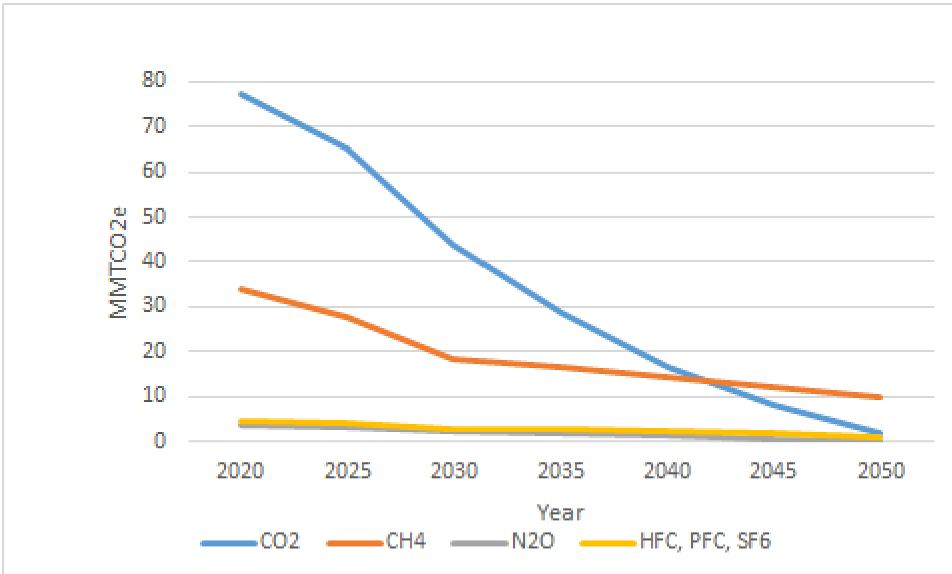
Exhibit 2-3: Projected Colorado GHG Emissions by Sector 2020-2050 ($MMTCO_2e$)



These projections do not include emissions and sinks from LULUCF. The estimation of carbon flux in forestry and land use activities is complex, and there are significant challenges in projecting future flux. This approach is consistent with prior published versions of the Colorado GHG Inventory.

Exhibit 2-4 shows projected emission trends by gas from 2020 to 2050 developed for the AQCC's GHG subcommittee and Colorado GHG Roadmap. Carbon dioxide is the largest GHG contributor, constituting over 70% of Colorado GHG emissions historically and remains the largest quantity in $MMTCO_2e$ through 2040. Emissions of CO_2 from fossil fuel combustion in Colorado began decreasing around 2010 and are projected to continue to decrease through 2050. Additional information on Sector and Sub-sector emissions breakdowns can be found in the supporting technical data for the GHG Roadmap.

Exhibit 2-4: Trend in Projected Colorado GHG Emissions by Gas



The projections included in this section, developed through the work performed for the GHG Roadmap and by the AQCC GHG Strategy Subcommittee, showcase the new approach adopted by Colorado for creating forward looking emissions estimates to guide legislative, regulatory, and policy conversations and planning. These projections describe a general trajectory necessary to achieve compliance with the economy-wide emissions reductions goals established by HB 1261. As described in the GHG Roadmap, Colorado is moving forward with a comprehensive, economy wide set of strategies to achieve the statutory requirements. The projections in future Bi-annual GHG Inventory reports will be informed by the data collected as these strategies are implemented and with more Colorado specific activity data and emissions factors as they become available.

3. ELECTRICAL POWER

3.1. Overview

The Electric Power Sector includes estimated carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions resulting from the combustion of fuels used to generate electricity in Colorado. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Electric Power sector accounted for approximately 23% of Colorado's GHG inventory in 2019.

This inventory covers the years 2005 - 2019. Two modules from the SIT model were used to estimate greenhouse gas emissions from this sector for 2005 - 2015: *Direct* CO_2 *Emissions from Combustion of Fossil Fuel* (CO_2FFC) and *CH_4 and N_2O Emissions from Stationary Combustion*. These modules also estimate CO_2, CH_4, and N_2O emissions from the combustion of fuel for residential, commercial, and industrial (RCI) uses, and CO_2 generated from the combustion of fuel for transportation. The RCI and transportation sectors are discussed separately in Chapters 4 and 5, respectively.

In addition to calculating GHG emissions resulting from the production of electricity in Colorado, the SIT model includes a separate *CO_2 Emissions from Electricity Consumption* module that estimates CO_2 emissions associated with the use of electricity in Colorado. This module estimates indirect emissions related to how power is used in Colorado by looking at an end-use analysis and estimating consumption emissions and transmissions losses. Emissions associated with electricity consumption are **not** incorporated into the totals for this inventory to avoid double counting emissions associated with electricity generation for 2005 - 2015 and are provided for information purposes only.

The Reference Scenario was used to estimate 2019 emissions from the electric power sector. The Reference Scenario accounts for the adoption of a RPS, along with fuel switching from coal to natural gas for electricity generation. The Reference Scenario does not estimate indirect emissions related to how power is used in Colorado.

3.2. SIT Model & Reference Scenario Results

Total estimated Electric Power GHG emissions include CO_2 emissions from the CO_2FFC module and CH_4 and N_2O emissions from the Stationary Combustion module. Exhibit 3-1 shows the model results for the electric power sector from each of these modules from 2005 - 2015 and 2019-year emissions from the Reference Scenario. The Reference Scenario does not estimate CH_4 and N_2O emissions from electricity generation.

Exhibit 3-1: CO_2e Estimated Emissions from Electrical Power Generation

Emissions (MMTCO2e)	2005	2010	2015	2019
Electric Utilities				
Coal	35.003	34.289	30.841	23.635726
Petroleum	0.019	0.016	0.006	0.000
Natural Gas	5.086	5.051	5.274	6.1228976
Subtotal CO_2 Emissions	40.108	39.356	36.121	29.75862
N_2O	0.171	0.168	0.151	NA
CH_4	0.012	0.012	0.011	NA
Subtotal CO_2e Emissions	0.183	0.179	0.162	NA
Total CO_2e Emissions	40.291	39.535	36.283	29.75862

3.3. Data and Methodology

The SIT CO_2FFC and Stationary Combustion modules estimate CO_2, CH_4, and N_2O emissions from sectors that consume fossil fuels and wood. The methodology is similar in all sectors, though this chapter addresses only electric power generation. The modules estimate emissions based on fuel consumption data, fuel carbon content, and emission factors. Emissions of CH_4 and N_2O were converted to CO_2e using GWP factors. Total estimated GHG emissions from electric power generation for 2005 - 2015 include the sum of CO_2, CH_4, and N_2O emissions, reported in MMT of CO_2e.

For informational purposes, the module *CO_2 Emissions from Electricity Consumption* was run and results are included in this chapter for 2005 - 2015. The module estimates indirect emissions related to how power is used in Colorado by looking at an end-use analysis and estimating consumption emissions (equipment efficiencies) and transmission losses. This information is **not** incorporated into the totals for the Colorado inventory from 2005 - 2015 to avoid double counting emissions associated with electric generation.

The Reference Scenario estimates CO_2 emissions from sources in the electricity generation sector that consume fossil fuels (coal, oil, natural gas).

3.3.1. CO_2FFC Module

This SIT module was used to estimate direct CO_2 emissions from the combustion of coal, natural gas, or other fuels in electric generation facilities. Default data was used, including fuel consumption by fuel type, carbon content coefficients, and an assumed combustion efficiency of 100%. No adjustment to the emission factors is made in the default mode to compensate for altitude changes. Equation 3-1 shows the general method used to estimate CO_2 emissions from fuel combustion. The calculation is based on consumption in Billion Btu (BBtu).

Equation 3-1: General Equation for Estimating CO_2 from Fossil Fuel Combustion[16]

Emissions ($MMTCO_2e$) = Consumption (Billion Btu) x Emission Factor (lbs C/Billion Btu) x 0.0005 (short tons/lb) x Combustion Efficiency (% as a decimal) x 0.9072 (metric tons/short ton) ÷ 10^6 (MMT/MT) x (44/12) (ratio of CO_2/C mass)

3.3.2. Stationary Combustion Module

The combustion process generates not only CO_2 but also CH_4 and N_2O. This module was used to estimate emissions of CH_4 and N_2O from the combustion of coal, natural gas, or other fuels in electric generation facilities, using the same default consumption data as the CO_2FFC module. The model includes default emission factors. Equation 3-2 shows the general method used to estimate CH_4 and N_2O emissions from combustion.

Equation 3-2: General Equation for Estimating N_2O or CH_4 from Stationary Sources[17]

Emissions ($MMTCO_2e$) = Consumption (Billion Btu) x Emission Factor (MT/Billion Btu) x GWP ÷ 10^6 (MMT/MT)

3.3.3. Electricity Consumption Module

The Electricity Consumption module estimates indirect greenhouse gas emissions from electricity consumption. In using this module, an important distinction between direct and indirect emissions must be made. Direct emissions, CO_2 from the CO_2FFC module and N_2O and CH_4 from the Stationary Source Combustion module, are a result of the combustion of fossil fuels at the electricity generating station. Indirect emissions occur at the point of use (e.g., residential space heating electricity consumption) and consider consumption emissions (equipment efficiencies) and

[16] U.S. EPA. User's Guide for Estimating Direct Carbon Dioxide Emissions from Fossil Fuel Combustion Using the State Inventory Tool (October 2017).

[17] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Stationary Combustion Using the State Inventory Tool (October 2017).

transmission line losses. Simply viewed, the light bulb at a home consumes a set amount of electricity independent of how much was generated at a power plant in the state, or imported from out of state, and independent of the amount of electricity lost in the transmission process and in the conversion of electricity to light.

The sum of indirect emissions may be more or less than the total emissions from direct electrical production, depending on the amount of power imported into or exported from the state. State inventories are generally based on direct emissions associated with electricity generation occurring within the state. EPA encourages states to include direct emissions in their inventory estimates and include indirect emissions as an informational-only line item.

The Electricity Consumption module calculates emissions based on emission factors, electricity consumption data, and the percent consumption by end-use sector and by equipment type within each sector. The tool provides default electricity consumption data. End-use sectors include residential, commercial, industrial, and transportation. Electricity consumption is allocated to each sector and between types of end-use equipment within each sector. Default emission factors for electricity consumption (lbs CO_2e/kWh) are provided. Emission factors are weighted to take into account numbers of households within each eGRID subregion in each state.[18] This weighted emission factor is intended to better reflect emissions related to electricity consumption within a state, and take into account the flow of electricity across state boundaries. Since these emission factors do not account for any transmission and distribution losses between the points of generation and the points of consumption, a transmission loss factor is applied.

Sectors and types of end-use equipment included in the model are shown in Exhibit 3-2. The general method used to estimate indirect CO_2e emissions from electricity consumption is shown in Equation 3-3.

[18] U.S. EPA. User's Guide for Estimating Indirect Carbon Dioxide Equivalent Emissions from Electricity Consumption Using the State Inventory Tool (March2018).

Exhibit 3-2: End Use Equipment by Sector[19]

Residential	Commercial	Industrial	Transportation
Space Heating	Space Heating	**Indirect Uses - Boiler Fuel:**	Automated Guideway
Air Conditioning	Cooling	Conventional Boiler Use	Bus (charged batteries)
Water Heating	Ventilation	CHP and/or Cogeneration	Cable Car
Refrigeration	Water Heating	**Direct uses: Total Process**	Commuter Rail
Other	Lighting	Process Heating	Heavy Rail
Appliances	Cooking	Process Cooling and	Inclined Plane
and Lighting	Refrigeration	Refrigeration	Light Rail
	Office Equipment	Machine Drive	Trolleybus
	Computers	Electro-Chemical Processes	Other
	Others	Other Process Use	
		Direct Uses-Total	
		Non-process:	
		Facility HVAC	
		Facility Lighting	
		Other Facility Support	
		On-Site Transportation	
		Other Non-process Use	

Equation 3-3: General Emissions Equation for Estimating Electricity Consumption[20]

Emissions ($MMTCO_2E$) = [(Total State Consumption (kWh) x End-Use Equipment Consumption (%)) ÷ (1-Transmission Loss Factor (%))] x Emission Factor (lbs CO_2e/kWh) x 0.0005 (short tons/lb) x 0.90718 (MT/short ton) ÷ 10^6 (MMT/MT)

Based on model default data, estimated GHG emissions associated with Colorado electricity consumption from 2005 - 2015 are shown in Exhibit 3-3.

[19] Ibid.
[20] Ibid.

Exhibit 3-3: Estimated Indirect Emissions of CO_2e from Electrical Consumption

Emissions ($MMTCO_2e$)	2005	2010	2015
Residential			
Space Heating	1.008	1.417	1.180
Air-conditioning	1.949	1.851	1.541
Water Heating	1.277	1.330	1.107
Refrigeration	2.016	2.035	1.695
Other Appliances and Lighting	8.803	9.471	7.888
Total	**15.050**	**16.100**	**13.410**
Commercial			
Space Heating	0.751	0.412	0.246
Cooling	2.275	2.013	1.661
Ventilation	2.247	2.623	2.399
Water Heating	0.321	0.139	0.062
Lighting	6.156	3.797	2.522
Cooking	0.159	0.301	0.308
Refrigeration	1.993	2.707	2.584
Office Equipment	0.656	0.797	0.738
Computers	1.135	1.700	1.661
Other	2.482	2.944	2.707
Total	**18.170**	**17.430**	**14.890**
Industrial			
Indirect Uses-Boiler Fuel	0.012	0.081	0.067
Conventional Boiler Use	0.012	0.081	0.067
Direct Uses-Total Process	8.326	10.234	8.440
Process Heating	0.994	1.310	1.080
Process Cooling & Refrigeration	0.730	0.979	0.808
Machine Drive	5.549	6.039	4.980
Electro-Chemical Processes	0.993	1.239	1.022
Other Process Use	0.061	0.667	0.550
Direct Uses-Total Non-process	2.163	2.905	2.395
Facility HVAC	1.115	1.566	1.291
Facility Lighting	0.771	0.927	0.765
Other Facility Support	0.258	0.328	0.270
Onsite Transportation	0.009	0.029	0.024
Other Nonprocess Use	0.009	0.055	0.045
Other	0.536	0.277	0.229
Total	**11.040**	**13.500**	**11.130**
Transportation			
Light Rail	0.018	0.041	0.047
Total	**0.018**	**0.041**	**0.047**
GRAND TOTAL	**44.282**	**47.076**	**39.477**

3.4. Uncertainties Associated with Emission Estimates for the Electric Power Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with each of the three modules assessing GHG emissions from the Electric Power sector. Some of the uncertainties associated with these modules are discussed below.

3.4.1. Uncertainty Associated With the CO_2FFC Module

The amount of CO_2 emitted from fossil fuel combustion depends upon the type and amount of fuel consumed, the carbon content of the fuel, and the fraction of the fuel that is oxidized. The more accurately these parameters are characterized, the more accurate the estimate of direct CO_2 emissions. There are uncertainties associated with each of these parameters.

Although statistics of total fossil fuel and other energy consumption are relatively accurate at the national level, there is more uncertainty associated with the state-level data.

Carbon content represents the maximum amount of carbon emitted per unit of energy released, assuming 100 percent combustion efficiency. Coal has the highest carbon content of the major fuel types, petroleum has about 75% the content of coal, and natural gas about 55%. Emissions from coal vary depending on composition of carbon, hydrogen, sulfur, ash, oxygen, and nitrogen. The carbon content of different petroleum fractions generally correlates with API (American Petroleum Institute) gravity, with lighter fractions, such as gasoline, usually having less carbon that heavier fractions, such as fuel oil. Natural gas is a mixture of several gases, and the carbon content depends on the relative proportions of methane, ethane, propane, and other constituents. The model provides an annual default carbon content for each fuel type.[21]

Fuel oxidation indicates the amount of carbon in a fuel that is oxidized during combustion, and is applied if the carbon is not completely oxidized. The fraction oxidized is assumed to be 100 percent for petroleum, coal, natural gas, and LPG.

The basis for the energy use data in the 1990-2015 base case has its origin in Energy Information Administration (EIA) State Energy Data System (SEDS) data, which is based on industry-reported information.[22] However, for comparative purposes, the

[21] U.S. EPA. User's Guide for Estimating Direct Carbon Dioxide Emissions from Fossil Fuel Combustion Using the State Inventory Tool (October 2017).
[22] Ibid.

following Exhibit 3-4 provides a comparison of EPA Air Markets Program Data (AMPD), formerly known as Clean Air Markets Data (CAMD) and the GHG Reporting Rule data for 2015. The 2015 AMPD data is approximately 5% higher than the SIT model 2015 output of 36.12 $MMTCO_2e$, and the GHG Reporting Rule Data is approximately 7% higher than the SIT model output. The difference is most likely due to differences in calculation methods between the SIT model and the facility-specific data.

Exhibit 3-4: Calendar Year 2015 GHG Reporting and AMPD (CAMD) Data[23]

FACILITY NAME	EPA GHG Reporting Program	AMPD (CAMD)*
	MT CO_2e	MT CO_2e
Comanche (470)	8,424,077	8,379,986
Craig	8,213,416	8,149,055
Pawnee	4,119,009	4,095,477
Hayden	3,088,889	3,072,336
Cherokee	3,058,002	3,036,812
Rawhide Energy Station	1,881,593	1,866,745
Martin Drake	1,650,039	1,636,819
Ray D Nixon	1,555,747	1,543,345
Fort St. Vrain	1,496,872	1,485,657
Valmont	1,110,627	1,103,418
Rocky Mountain Energy Center	827,192	824,399
Front Range Power Plant	758,910	758,144
Nucla	543,775	538,701
Pueblo Airport Generating Station	541,700	541,154
J.M. Shafer Generating Station	339,262	338,583
Blue Spruce Energy Center	266,601	266,277
Fountain Valley Power Plant	184,633	183,794
Spindle Hill Energy Center	109,020	108,775
Manchief Generating Station	108,886	108,492
Arapahoe Combustion Turbine Facility	58,691	58,576
Zuni	23,648	23,624
Brush Power Projects	22,693	8,502
Limon Generating Station	20,247	20,099
Frank Knutson Station	4,851	4,795
Valmont Combustion Turbine Facility	0	0
Subtotal of AMPD (CAMD) Units	38,408,380	38,153,565
Colorado Energy Nations Company LLC (Golden Facility)	379,088	*
PUBLIC SERVICE CO DENVER STEAM PLT	61,068	*
University of Colorado Boulder - Utility Services	31,527	*
PLAINS END Generating Station	23,662	*
Eagle Valley Clean Energy	27	*
Subtotal of Smaller Units	495,372	*
TOTAL REPORTED CO2e	**38,903,752**	**38,153,565**
*Only facilities of 25 MW or more report to AMPD (CAMD)		

[23] https://ghgdata.epa.gov/ghgp/main.do#, assessed 11/5/18, and https://ampd.epa.gov/ampd/, accessed 11/5/18

3.4.2. Uncertainty Associated With the Stationary Combustion Module

The amount of CH_4 and N_2O emitted from stationary combustion depends upon numerous variables, including the amount and type of fuel burned, type of combustion device, the size and vintage of the combustion device, the maintenance and operation of the equipment, and the type of pollution control technology used. The level of N_2O emissions is dependent on combustion temperature, with more N_2O generated at higher temperatures. Methane and non-methane volatile organic compounds (VOCs) are unburned gaseous combustibles that are emitted in small quantities due to incomplete combustion. More of these gases are released when combustion temperatures are relatively low. Larger, higher efficiency combustion facilities tend to reach higher combustion temperatures and thus emit less of these gases, but more N_2O.

The more detailed the information available on the combustion activity, the lower the uncertainty. The contribution of CH_4 and N_2O to overall emissions is small and the estimates are highly uncertain. Uncertainties exist in both the emission factors and the activity data used to derive emission estimates.

3.4.3. Uncertainty Associated With the Electricity Consumption Module

Although statistics of electricity consumption are relatively accurate at the national level, there is more uncertainty associated with the state-level data. In addition, the allocation of this consumption to individual end-use sectors (i.e. residential, commercial, industrial, and transportation) at the state level is more uncertain than at the national level. Allocation of consumption to specific types of end-use equipment adds additional uncertainty.

4. RESIDENTIAL, COMMERCIAL, INDUSTRIAL (RCI) FUEL USE

4.1. Overview

The Residential, Commercial, Industrial (RCI) Fuel Use sector includes estimated carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions resulting from the combustion of fuels for various heating and commercial process purposes in Colorado. This covers fuel use by end users for heating homes and businesses and by commercial and industrial users to generate heat used in industrial processes. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Residential, Commercial, and Industrial sectors accounted for approximately 21% of Colorado's GHG inventory in 2019.

This inventory covers the years 2005 -2019. Two modules from the SIT model were used to estimate greenhouse gas emissions from the RCI sectors for 2005 - 2015: *Direct* CO_2 *Emissions from Combustion of Fossil Fuel* (CO_2FFC) and *CH_4 and N_2O Emissions from Stationary Combustion*. These modules also estimate CO_2, CH_4, and N_2O emissions from the combustion of fuel for electric power generation and CO_2 generated from the combustion of fuel for transportation. The electric power and transportation sectors are discussed separately in Chapters 3 and 5, respectively, and non-combustion emissions from industrial processes is addressed in Chapter 6.

The Reference Scenario was used to estimate 2019 emissions from the RCI sectors.

4.2. SIT Model and Reference Scenario Results

Total estimated RCI combustion GHG emissions include CO_2 emissions from the SIT CO_2FFC module and CH_4 and N_2O emissions from the Stationary Combustion module. Exhibit 4-1 shows the SIT model results for combustion from the residential, commercial, and industrial sectors from each of these modules for 2005 - 2015, and results from the Reference Scenario for 2019. The Reference Scenario does not estimate CH_4 and N_2O emissions from the RCI sectors.

Exhibit 4-1: Estimated CO_2e Emissions from Residential, Commercial and Industrial Fossil Fuel Combustion

Emissions ($MMTCO_2e$)	2005	2010	2015	2019
Residential				
Coal	0.022	0.000	0.000	0.000
Petroleum	0.817	0.770	0.648	1.182
Natural Gas	6.774	7.081	6.854	6.769
Subtotal CO_2 Emissions	7.613	7.851	7.502	7.951
N_2O	0.014	0.015	0.015	NA
CH_4	0.069	0.077	0.076	NA
Subtotal CO_2e Emissions	0.083	0.092	0.090	0.000
Subtotal Sector Emissions	7.696	7.943	7.593	7.951
Commercial				
Coal	0.254	0.566	0.007	0.000
Petroleum	0.452	0.565	0.987	1.032
Natural Gas	3.385	3.111	3.025	3.136
Subtotal CO_2 Emissions	4.092	4.242	4.019	4.168
N_2O	0.005	0.007	0.006	NA
CH_4	0.018	0.020	0.020	NA
Subtotal CO_2e Emissions	0.023	0.027	0.026	0.000
Subtotal Sector Emissions	4.115	4.269	4.045	4.168
Industrial				
Coal	0.140	0.209	0.354	0.666
Petroleum	3.179	2.919	3.213	3.038
Natural Gas	9.493	10.828	10.465	11.354
Subtotal CO_2 Emissions	12.812	13.956	14.032	15.058
N_2O	0.013	0.013	0.014	NA
CH_4	0.008	0.008	0.009	NA
Subtotal CO_2e Emissions	0.020	0.021	0.023	0.000
Subtotal Sector Emissions	12.833	13.978	14.055	15.058
Total CO_2e Emissions	24.643	26.190	25.692	27.177

4.3. Data and Methodology

The SIT CO_2FFC and Stationary Combustion modules estimate CO_2, CH_4, and N_2O emissions from sectors that consume fossil fuels and wood. The methodology is similar in all sectors, though this chapter addresses only emissions from combustion in the RCI sectors. The modules estimate emissions based on fuel consumption data and emission factors. Emissions of CH_4 and N_2O were converted to CO_2e using GWP factors. Total estimated GHG emissions from each sector include the sum of sector CO_2, CH_4, and N_2O emissions for 2005 - 2015, reported in MMT of CO_2e.

The Reference Scenario estimates CO_2 emissions from sources in the RCI sectors that consume fossil fuels (coal, petroleum, natural gas).

4.3.1. CO_2FFC Module

This module was used to estimate direct CO_2 emissions from the combustion of coal, natural gas, and other fuels in the RCI sectors. Default data was used, including fuel consumption by fuel type, carbon content coefficients, and an assumed combustion efficiency of 100%. No adjustment to the emission factors is made in the default mode to compensate for altitude changes. The combustion of biomass and biomass-based fuels, such as wood, is not included in emissions totals because biomass fuels are of biogenic origin. It is assumed that the carbon released during consumption of biomass is recycled as forests and crops regenerate, causing no new addition of CO_2 to the atmosphere.

The Industrial sector uses fossil fuels for a variety of non-combustion purposes, such as the production of solvents, lubricants, synthetic rubber, and other products. The CO_2FFC module estimates carbon stored in non-energy uses for each state by taking the total state consumption of each type of fuel, applying a default percentage of each fuel type used for non-energy purposes, and then applying a default storage factor (i.e. the amount of carbon in non-energy uses that typically remains stored for longer than 20 years) to the quantity of each fuel used for non-energy purposes. This non-energy consumption is then subtracted from the total consumption to yield the net combustible consumption. More detailed information on fuel types used in each sector is shown in Exhibit 4-2 below.

Exhibit 4-2: Fuel Types Consumed by Sector

Residential	Commercial	Industrial	
Coal	Coal	Coking Coal Other Coal	
Natural Gas	Natural Gas	Natural Gas	
Petroleum: Distillate Fuel (Diesel) Kerosene LPG	Petroleum: Distillate Fuel Kerosene LPG Motor Gasoline Residual Fuel	Petroleum: Distillate Fuel Kerosene LPG Motor Gasoline Residual Fuel Lubricants Asphalt & Road Oil Crude Oil Feedstocks Naphthas < 401°F Other Oils >401 °F Misc. Petroleum Products	Petroleum Coke Pentanes Plus Still Gas Special Naphthas Unfinished Oils Waxes Aviation Gasoline Blending Components Motor Gasoline Blending Components
Wood*	Wood*	Wood*	
Other	Other	Other	

*CO_2 emissions from wood combustion are considered carbon neutral and are not included in the CO2FFC module results. CH_4 and N_2O emissions from wood combustion are included in emission results.

Equation 4-1 shows the general method used to estimate CO_2 emissions from fuel combustion. No adjustment to the emission factors is made to compensate for altitude changes in the default mode. Equation 4-2 shows the general method used to estimate CO_2 emissions from fuel combustion in the Industrial sector, taking into account the non-combustion use of some fossil fuels.

Equation 4-1: General Equation for Estimating CO_2 from Fossil Fuel Combustion[24]

Emissions ($MMTCO_2e$) = Consumption (Billion Btu) x Emission Factor (lbs C/BBtu) x 0.0005 (short tons/lb) x Combustion Efficiency (% as a decimal) x 0.9072 (MT/short ton) ÷ 10^6 (MMT/MT) x (44/12) (ratio of CO_2/C mass)

Equation 4-2: General Equation for Estimating CO_2 from Fossil Fuel Combustion in the Industrial Sector[25]

Emissions ($MMTCO_2E$) = [Total Consumption (Billion Btu) – (Non-Energy Consumption (Billion Btu) x Storage Factor (%))] x Emission Factor (lbs C/BBtu) x Combustion Efficiency (as a decimal)) x 0.9072 (MT/short ton) ÷ 10^6 (MMT/MT) x 44/12 (ratio of CO_2 to C mass)

4.3.2. Stationary Combustion Module

The combustion process generates not only CO_2, but also CH_4 and N_2O. This module was used to estimate emissions of CH_4 and N_2O from the combustion of coal, natural gas, and other fuels in the RCI sectors using the same default fuel types and consumption data as the CO_2FFC module. Emissions of CH_4 and N_2O from the combustion of biomass and biomass-based fuels, such as wood, are included in stationary combustion totals.

The model includes default emission factors and uses a GWP of 25 for CH_4 and 298 for N_2O. Equation 4-3 shows the general method used to estimate CH_4 and N_2O emissions from combustion. Equation 4-4 shows the general method used to estimate CH_4 and N_2O emissions from fuel combustion in the industrial sector, taking into account the non-combustion use of some fossil fuels.

Equation 4-3: General Equation for Estimating CH_4 or N_2O from Fossil Fuel Combustion[26]

Emissions ($MMTCO_2e$) = Consumption (BBtu) x Emission Factor (MT/BBtu) x GWP ÷ 10^6 (MMT/MT)

[24] U.S. EPA. User's Guide for Estimating Direct Carbon Dioxide Emissions from Fossil Fuel Combustion Using the State Inventory Tool (October 2017)
[25] Ibid.
[26] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Stationary Combustion Using the State Inventory Tool (October 2017).

Equation 4-4: General Equation for Estimating CH_4 or N_2O from Fossil Fuel Combustion in the Industrial Sector[27]

Emissions ($MMTCO_2E$) = [Total Consumption (BBtu) – (Non-Energy Consumption (BBtu) x Storage Factor (%))] x Emission Factor (MT/BBtu) x GWP ÷ 10^6 (MMT/MT)

4.4. Uncertainties Associated With Emission Estimates for the RCI Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with both of the modules assessing GHG emissions from the RCI sectors. Some of the uncertainties associated with these modules are discussed below.

4.4.1. Uncertainty Associated With the CO_2FFC Module

The amount of CO_2 emitted from fossil fuel combustion depends upon the type and amount of fuel consumed, the carbon content of the fuel, and the fraction of the fuel that is oxidized. The more accurately these parameters are characterized, the more accurate the estimate of direct CO_2 emissions. There are uncertainties associated with each of these parameters.

Although statistics of total fossil fuel and other energy consumption are relatively accurate at the national level, there is more uncertainty associated with the state-level data.

Carbon content represents the maximum amount of carbon emitted per unit of energy released, assuming 100 percent combustion efficiency. Coal has the highest carbon content of the major fuel types, petroleum has about 75% the content of coal, and natural gas about 55%. Emissions from coal vary depending on composition of carbon, hydrogen, sulfur, ash, oxygen, and nitrogen. The carbon content of different petroleum fractions generally correlates with API (American Petroleum Institute) gravity, with lighter fractions, such as gasoline, usually having less carbon than heavier fractions, such as fuel oil. Natural gas is a mixture of several gases, and the carbon content depends on the relative proportions of methane, ethane, propane,

[27] Ibid.

and other constituents. The model provides an annual default carbon content for each fuel type.[28]

Fuel oxidation indicates the amount of carbon in a fuel that is oxidized during combustion, and is applied if the carbon is not completely oxidized. The fraction oxidized is assumed to be 100% for petroleum, coal, natural gas, and LPG.

4.4.2. Uncertainty Associated With the Stationary Combustion Module

The amount of CH_4 and N_2O emitted from stationary combustion depends upon numerous site-specific variables, including the amount and type of fuel burned, type of combustion device, the size and vintage of the combustion device, the maintenance and operation of the equipment, and the type of pollution control technology used. The level of N_2O emissions is dependent on combustion temperature, with more N_2O generated at higher temperatures. Methane and non-methane volatile organic compounds (VOCs) are unburned gaseous combustibles that are emitted in small quantities due to incomplete combustion; more of these gases are released when combustion temperatures are relatively low. Larger, higher efficiency combustion facilities tend to reach higher combustion temperatures and thus emit less of these gases and more N_2O.

The more detailed the information available on the combustion activity, the lower the uncertainty. The contribution of CH_4 and N_2O to overall emissions is small and the estimates are highly uncertain. Uncertainties exist in both the emission factors and the activity data used to derive emission estimates.

[28] U.S. EPA. User's Guide for Estimating Direct Carbon Dioxide Emissions from Fossil Fuel Combustion Using the State Inventory Tool (October 2017).

5. TRANSPORTATION

5.1. Overview

The Transportation sector includes estimated carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions resulting from the combustion of fuels used for transportation in Colorado. This consists primarily of on-highway vehicles, but also includes emissions from non-highway vehicles such as boats, locomotives, construction equipment and aircraft. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Transportation sector accounted for approximately 21% of Colorado's GHG inventory in 2019.

This inventory covers the years 2005 - 2019. Two modules from the SIT model were used to estimate greenhouse gas emissions from this sector for 2005 - 2015: *Direct CO_2 Emissions from Combustion of Fossil Fuel* (CO_2FFC) and *CH_4 and N_2O Emissions from Mobile Combustion*. The CO_2FFC module also estimates CO_2 emissions from the combustion of fuel for residential, commercial, and industrial (RCI) uses, and electric power generation. The Electric Power and RCI sectors are discussed separately in Chapters 3 and 4, respectively.

The Reference Scenario was used to estimate 2019 emissions from the Transportation sector.

5.2. SIT Model and Reference Scenario Results

Total estimated Transportation GHG emissions include direct CO_2 emissions from the SIT CO_2FFC module and CH_4 and N_2O emissions from the Mobile Combustion module for 2005 - 2015. The Mobile Combustion module breaks out emissions by category of vehicle (highway or off-road) and fuel type (gasoline, diesel, or alternative). Exhibit 5-1 shows the model results for the transportation sector from each of these modules for 2005 - 2015, and results from the Reference Scenario for 2019. The Reference Scenario does not estimate CH_4 and N_2O emissions from the Transportation sector.

For 2019, emissions from all light duty vehicles (LDV) are grouped into passenger cars for gasoline- and diesel-fueled vehicles since the Reference Scenario does not break out LDV by passenger cars and light duty trucks. Similarly, for 2019, medium duty vehicles (MDV) are grouped with HDV since the SIT does not break out MDV, but the Reference Scenario does. Finally, for 2019, buses are grouped under heavy duty vehicles (HDV) in the gasoline and diesel categories since the SIT does not break out buses for those categories, but the Reference Scenario does. Note that the "alternative fuel vehicles" category includes vehicles that burn methanol, ethanol, liquefied petroleum gas (LPG), liquefied natural gas (LNG), or compressed natural gas (CNG).

Exhibit 5-1: Estimated CO_2e Emissions from Transportation-Related Fossil Fuel Combustion

Emissions ($MMTCO_2e$) by Vehicle Type/Fuel Type	2005	2010	2015	2019
Gasoline Highway				
Passenger Cars	0.476	0.302	0.170	16.391
Light-Duty Trucks	0.361	0.104	0.060	NA
Heavy-Duty Vehicles	0.026	0.007	0.004	0.004
Motorcycles	0.001	0.002	0.002	NA
Subtotal Emissions	0.863	0.415	0.236	16.395
Diesel Highway				
Passenger Cars	0.000	0.000	0.000	0.805
Light-Duty Trucks	0.000	0.000	0.000	NA
Heavy-Duty Vehicles	0.008	0.010	0.005	5.334
Subtotal Emissions	0.008	0.010	0.006	6.139
Non-Highway				
Boats	0.001	0.001	0.001	NA
Locomotives	0.002	0.007	0.007	NA
Farm Equipment	0.005	0.006	0.005	NA
Construction Equipment	0.012	0.012	0.026	NA
Aircraft	0.051	0.046	0.038	4.344
Other*	0.005	0.003	0.005	NA
Subtotal Emissions	0.076	0.075	0.081	4.344
Alternative Fuel Vehicles				
Light-Duty Vehicles	0.001	0.002	0.003	0.280
Heavy-Duty Vehicles	0.004	0.006	0.006	0.283
Buses	0.000	0.001	0.001	0.000
Subtotal Emissions	0.006	0.009	0.010	0.563
TOTAL CO2e EMISSIONS VEHICLE TYPE	**0.953**	**0.509**	**0.333**	**27.441**
Direct CO_2 Emissions by Fuel Type				
Petroleum	29.099	28.482	27.314	26.878
Natural Gas	0.734	0.774	0.521	0.563
Subtotal CO_2 Emissions	29.834	29.256	27.835	27.441
TOTAL CO_2e EMISSIONS FUEL TYPE	**30.787**	**29.764**	**28.168**	**27.441**

*"Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment

5.3. Data and Methodology

The SIT CO_2FFC module estimates the CO_2 emissions from sectors that consume fossil fuels and wood. The methodology is similar in all sectors, though this chapter addresses only transportation. The module estimates emissions based on fuel consumption data and emission factors.

The Mobile Combustion module estimates CH_4 and N_2O emissions from fossil fuel combustion by mobile sources, both on-road and off-road. Emissions of CH_4 and N_2O are converted to CO_2e using global warming potential factors. The provided default input data and emission factors were used. Total estimated GHG emissions from transportation include the sum of CO_2, CH_4, and N_2O emissions, reported in MMT of CO_2e.

The Reference Scenario estimates CO_2 emissions from consumption of fossil fuels (petroleum and natural gas) by aviation, buses, light duty vehicles (LDV), medium duty vehicles (MDV), heavy duty vehicles (HDV), and “other” modes of transportation, which include those that burn alternative fuels.

5.3.1. CO_2FFC Module

This module was used to estimate direct CO_2 emissions from the combustion of fossil fuels for transportation. Default data was used, including fuel consumption by fuel type, carbon content coefficients for each fuel type, and an assumed combustion efficiency of 100%. No adjustment to the emission factors is made in the default mode to compensate for altitude changes. Motor gasoline consumption data includes ethanol that is blended into gasoline. Ethanol is not a fossil fuel and is considered to be carbon-neutral, so the default motor gasoline consumption data in the SIT model has been adjusted to remove the portion of blended gasoline known to be ethanol. The quantity of ethanol burned as fuel is included in the following table for information only. Types and quantities of fossil fuels used for transportation for 2005 - 2019 are shown in Exhibit 5-2 below in Billion British thermal units (BBtu). The Reference Scenario did not break out individual fuel types consumed in BBtu, only total fuel consumed in BBtu for the Transportation sector in 2019.

Exhibit 5-2: Colorado Fuel Use for Transportation Sector (BBtu)

Fuel Type	2005	2010	2015	2019
Aviation Gasoline	655	581	449	NA
Distillate Fuel	76,952	84,341	81,960	NA
Jet Fuel - Kerosene	69,852	63,841	52,508	NA
Jet Fuel - Naphtha	-	-	-	NA
LPG	296	268	932	NA
Motor Gasoline	255,646	244,430	241,466	NA
Natural Gas	13,841	14,589	9,813	NA
Residual Fuel	-	-	-	NA
Other	-	-	-	NA
Lubricants	2,149	2,005	2,104	NA
Ethanol**	3,696	10,184	17,650	NA
TOTAL	423,087	420,239	406,882	395,549
** Ethanol is considered a carbon-neutral fuel and is not included in emissions calculations				

Equation 5-1 shows the general method used to estimate CO_2 emissions from fuel combustion.

Equation 5-1: General Equation for Estimating CO_2 from Fossil Fuel Combustion[29]

Emissions ($MMTCO_2e$) = Consumption (Billion Btu) x Emission Factor (lbs C/BBtu) x 0.0005 (short tons/lb) x Combustion Efficiency (% as a decimal) x 0.9072 (MT/short ton) ÷ 10^6 (MMT/MT) x (44/12) (ratio of CO2/C mass)

5.3.2. Mobile Combustion Module

The combustion process generates not only CO_2, but also CH_4 and N_2O. This module was used to estimate emissions of CH_4 and N_2O from the combustion of fossil fuels for transportation. Emissions of these gases are strongly influenced by a variety of factors, including engine type, fuel combusted, control technology, cold start operation, and operating conditions (low speed, aggressive driving). To estimate emissions, this module first considers four categories of vehicles:

[29] U.S. EPA. User's Guide for Estimating Direct Carbon Dioxide Emissions from Fossil Fuel Combustion Using the State Inventory Tool (October 2017).

- Gasoline Highway (passenger cars, light-duty trucks, heavy-duty vehicles, motorcycles);
- Diesel Highway (passenger cars, light-duty trucks, heavy-duty vehicles);
- Non-Highway (boats, locomotives, farm equipment, construction equipment, aircraft, and other, including snowmobiles, gasoline-powered equipment, heavy-duty diesel-powered utility equipment); and
- Alternative Fuel Vehicles (light-duty vehicles, heavy duty vehicles, buses).

Emissions for off-road vehicles are estimated using fuel consumption and default fuel-specific emission factors for each fuel type. Emissions for on-road vehicles are estimated based on vehicle miles traveled (VMT) and default emission factors for the vehicle type by model year. The model converts metric tons of CH_4 and N_2O to CO_2e through the application of GWP factors. Equation 5-2 shows the general method used to estimate CH_4 and N_2O emissions from mobile combustion.

Equation 5-2: General Equation for Estimating CH_4 and N_2O from Fossil Fuel Combustion[30]

$$\text{Emissions} = \Sigma(EF_{abc} \times \text{Activity}_{abc})$$

Where,
- EF = emissions factor (e.g., grams/kilometer traveled);
- Activity = activity level measured in the units appropriate to the emission factor (e.g., miles);
- a = fuel type (e.g., diesel or gasoline);
- b = vehicle type (e.g., passenger car, light duty truck, etc.); and
- c = emission control type (if any)

The annual VMT breakdown for highway vehicles by vehicle class used in this inventory for 2005 - 2015 is shown in Exhibit 5-3 below. VMT data for 2019 used in the Reference Scenario is currently unavailable but will be added to this inventory when it is finalized.

[30] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Mobile Combustion Using the State Inventory Tool (October 2017).

Exhibit 5-3: Colorado Annual Vehicle Miles Traveled by Vehicle Class (Annual VMT in Million miles)[31]

Vehicle Class	2005	2010	2015
Heavy-Duty Diesel Vehicle	3,208	4,529	4,587
Heavy-Duty Gas Vehicle	474	199	209
Light-Duty Diesel Truck	485	397	413
Light-Duty Diesel Vehicle	146	160	175
Light-Duty Gas Truck	16,131	9,458	9,825
Light-Duty Gas Vehicle	27,354	31,902	34,908
Motorcycle	164	293	320
Total	47,962	46,940	50,437

5.4. Uncertainties Associated With Emission Estimates for the Transportation Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with each of the modules assessing GHG emissions from the Transportation sector. Some of the uncertainties associated with these modules are discussed below.

5.4.1. Uncertainty Associated With the CO_2FFC Module

The amount of CO_2 emitted from fossil fuel combustion depends upon the type and amount of fuel consumed, the carbon content of the fuel, and the fraction of the fuel that is oxidized. The more accurately these parameters are characterized, the more accurate the estimate of direct CO_2 emissions.

5.4.2. Uncertainty Associated With the Mobile Combustion Module

The following discussion on Transportation Sector uncertainties is extracted and edited from the EPA 2018 SIT model Mobile Combustion module.

5.4.2.1. Highway Vehicle Uncertainties

CH_4 and N_2O emissions estimates are based on activity data (vehicle miles traveled) and emission factors. Information on VMT for each state is gathered annually by the

[31] U.S. State Inventory Tool, Methane and Nitrous Oxide Emissions from Mobile Combustion Module (October 1, 2017)

Federal Highway Administration. States use different methods to collect this data, leading to varying degrees of uncertainty associated with state activity data. In addition, the model apportions state VMT data among different vehicle types based on national averages. Additional uncertainty is thus introduced due to state-specific differences in consumer preferences for vehicle types.

Uncertainties surrounding emission factors are relatively high, since emissions vary depending on a number of factors. These factors include ambient temperature, vehicle speeds, gasoline volatility, and other variables. Values for all of these factors can vary significantly depending on many different variables, such as driving conditions and vehicle characteristics. N_2O emission factors were developed using a variety of sources. Factors for most gasoline vehicles were scaled from the factor for passenger cars based on ratios of fuel economy.

5.4.2.2. Non-Highway Vehicle Uncertainties

Emission estimates for non-highway sources are also based on activity data (fuel consumption) and emission factors. Fuel consumption data is generally gathered at the national level and then apportioned to states. This apportionment introduces some uncertainty. Emission factors reflect significant uncertainties. Little research has been conducted regarding emissions from these modes and technologies, and vehicle characteristics have changed since the factors were first developed.

6. INDUSTRIAL PROCESSES

6.1. Overview

The Industrial Processes sector includes estimated carbon dioxide (CO_2), hydrofluorocarbon (HFC), perfluorocarbon (PFC), and sulfur hexafluoride (SF_6) emissions from various industrial processes. For Colorado these processes consist of: cement production; lime manufacture; limestone and dolomite use; soda ash manufacture and consumption; iron and steel production; ammonia manufacture and urea consumption; consumption of substitutes for ozone depleting substances; semiconductor manufacture; and electric power transmission and distribution. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. In this inventory, a factor of 22,800 is used for SF_6. Emissions from the Industrial Process sector accounted for approximately 4% of Colorado's GHG inventory in 2019.

This inventory covers the years 2005 - 2019. The SIT *Industrial Processes* module was used to estimate non-combustion greenhouse gas emissions from this sector for 2005 - 2015. The SIT *Direct CO_2 emissions from Combustion of Fossil Fuel* (CO_2FFC) and *CH_4 and N_2O Emissions from Stationary Combustion* modules were used to estimate greenhouse gas emissions from the combustion of fossil fuels in this sector for 2005 - 2015, and those results are discussed in Chapter 4. The Reference Scenario was used to estimate emissions from this sector for 2019.

6.2. SIT Model and Reference Scenario Results

Total estimated Industrial Process GHG emissions from the SIT model includes emissions of CO_2 from non-combustion uses of fossil fuels and CO_2e from consumption of HFCs, PFCs, and SF_6. Exhibit 6-1 shows the SIT model results for the industrial processes module and from the Reference Scenario.

Exhibit 6-1: Estimated CO_2e Emissions from Industrial Processes

Emissions ($MMTCO_2e$)	2005	2010	2015	2019
Carbon Dioxide Emissions	1.334	1.185	1.490	1.490
Cement Manufacture	0.623	0.559	0.769	0.769
Lime Manufacture	0.295	0.276	0.365	0.365
Limestone and Dolomite Use	0.031	0.005	0.010	0.010
Soda Ash	0.041	0.036	0.035	0.035
Iron & Steel Production	0.340	0.305	0.305	0.305
Urea Consumption	0.004	0.004	0.007	0.007
Subtotal Emissions	**1.334**	**1.185**	**1.490**	**1.490**
HFC, PFC, and SF6 Emissions				
ODS Substitutes	1.574	2.305	2.861	3.009
Semiconductor Manufacturing	0.137	0.102	0.097	0.097
Electric Power Transmission and Distribution Systems	0.109	0.083	0.060	0.060
Subtotal Emissions	**1.820**	**2.490**	**3.018**	**3.165**
TOTAL EMISSIONS	**3.154**	**3.675**	**4.508**	**4.655**

6.3. Data and Methodology

The Industrial Processes sector uses fossil fuels for a variety of non-combustion purposes, such as the production of solvents, lubricants, synthetic rubber, and other products. The SIT model assumes carbon stored in non-energy uses typically remains stored for longer than 20 years. The module estimates CO_2 and N_2O emissions from these non-combustion uses of fossil fuels, and emissions from consumption of HFCs, PFC, and SF_6. Emissions are estimated based on activity data, such as production or consumption quantities, and default emission factors. Default activity data utilized includes:

- quantity of cement clinker produced;
- quantity of high-calcium and dolomitic lime produced;
- quantity of limestone and soda ash consumed;
- quantity of iron and steel produced; and
- quantity of urea consumed.

Default production and consumption data in the model was taken from several different national data sources and is documented in the User's Guide.[32]

[32] U.S. EPA. User's Guide for Estimating Carbon Dioxide, Nitrous Oxide, HFC, PFC, and SF_6 Emissions from Industrial Processes Using the State Inventory Tool (March 2018)

Emissions of HFCs, PFCs, and SF_6 from ODS (ozone depleting substances) substitute consumption and semiconductor manufacturing are estimated by apportioning national emissions based on state population. Because the model apportions national emissions data, activity data and emission factors are not required for these activities at the state level. SF_6 emissions from electric power transmission and distribution are estimated based on annual consumption data and an emission factor. Emissions of SF_6 are converted to CO_2e using a global warming potential factor.

Equation 6-1 shows the general method used to estimate CO_2 emissions from industrial processes. Equation 6-2 shows the general method used to estimate HFC, PFC, and SF_6 emissions from ODS substitute consumption and semiconductor manufacturing.

Equation 6-1: General Equation for Estimating CO_2 from Industrial Processes[33]

Emissions (MMTCO2e) = Production or Consumption (MT) x Emission Factor (MTCO2/MT production or consumption) ÷ 10^6 (MMT/MT)

Equation 6-2: General Equation for Apportioning Emissions from the Consumption of Substitutes for ODS[34]

Emissions (MMTCO_2e) = National emissions (MTCO2e) x State Population ÷ National Population ÷ 10^6 (MMT/MT)

6.4. Uncertainties Associated With Emission Estimates for the Industrial Processes Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with the industrial processes module. In estimating emissions from cement production, there is variance in the portion of calcinated cement kiln dust and the percentage of clinker constituted by lime. There is uncertainty in both the manufacture and use of lime due to variability in the chemical composition of lime. There is uncertainty associated with the manufacture and consumption of soda ash due to the variance in emissions depending on end use. Apportionment by population is used to estimate HFC, PFC, and some SF_6 emissions. Uncertainty in this area is due to variability in use and possible differences in management practices from one region to another.

[33] Ibid.
[34] Ibid.

7. COAL MINING AND ABANDONED MINES

7.1. Overview

The Coal Mining sector includes estimated methane (CH_4) emissions in Colorado related to the production of coal at active mines and ongoing methane leakage from abandoned coal mines. The origins of the emissions are distinctly different from those calculated in the SIT fossil fuel combustion and stationary combustion modules, which estimate carbon dioxide (CO_2), CH_4, and nitrous oxide (N_2O) emissions from the combustion of coal. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Coal Mining sector accounted for just over 1% of Colorado's GHG inventory in 2019.

This inventory covers the years 2005 - 2019. Emissions from this sector were estimated using the SIT *Methane Emissions from Coal Mining* module. Estimated emissions from the combustion of coal are discussed in Chapters 3 and 4. The Reference Scenario was used to estimate emissions from this sector for 2019.

7.2. SIT Model and Reference Scenario Results

Estimated Coal Mining GHG emissions include methane emissions from the production of coal and from ongoing methane leakage from abandoned underground coal mines. Exhibit 7-1 summarizes methane emissions from coal mining in Colorado. The data shows a significant decrease in emissions from 2010 to 2019, which is discussed in more detail later in this chapter.

Exhibit 7-1: Estimated CO_2e Emissions from Coal Mining Activities

Emissions ($MMTCO_2e$)	2005	2010	2015	2019
Coal Mining	6.436	7.830	1.581	1.581
Abandoned Coal Mines	0.374	0.307	0.270	0.242
Vented	0.078	0.065	0.058	NA
Sealed	0.290	0.238	0.209	NA
Flooded	0.006	0.003	0.003	NA
Total	**6.810**	**8.137**	**1.851**	**1.823**

7.3. Data and Methodology

The SIT coal module estimates CH_4 emissions from coal production from underground and surface mines, post-production activities such as transportation and coal handling, and CH_4 leakage from abandoned underground coal mines. For surface mines and for post-production activities from both surface and underground mines, emissions are estimated based on coal production and emission factors. Emission factors are specific to each coal basin and type of mine (underground or surface). Emissions from production at underground mines are calculated based on estimated emissions from ventilation systems and degasification systems, taking into account any recovered methane used for energy purposes.

Emissions from abandoned underground mines are highest at the time of abandonment and decrease over time. These emissions are modeled using a decline equation. This calculation applies only to underground mines, and the specific form of the equation depends on the degree to which the mine is sealed.

The tool provides default coal production data, default emission factors, and estimated ventilation and degasification emissions, as well as a list of abandoned mines. Emissions of CH_4 are converted to CO_2e using a global warming potential factor.

The general calculation methods for emissions from mining activities are shown in Equations 7-1, 7-2, and 7-3 below. This includes production from underground mines, production from surface mines, and post-production activities.

Equation 7-1: General Equation for Estimating CH_4 from Underground Mining[35]

Emissions ($MTCO_2e$) = {Measured Ventilation Emissions (million ft^3 CH_4) + [Degasification Systems Emissions (million ft^3 CH_4) - CH_4 Recovered from Degasification Systems and Used for Energy (million ft^3)]} * 18.92 g/ft^3 * $10^6 ft^3$/million ft^3 * 10^{-6} MT/g * GWP

Equation 7-2: General Equation for Estimating CH_4 from Surface Mining[36]

Emissions ($MTCO_2e$) = Surface Coal Production (thousand short tons) * Basin Specific Emission Factor (ft^3/short ton) * 18.92 g/$ft^3 CH_4$ * $10^3 ft^3$/'000 ft^3 * 10^{-6} MT/g * GWP

[35] U.S. EPA. User's Guide for Estimating Methane Emissions from Coal Mines and Abandoned Coal Mines Using the State Inventory Tool (October 2017).
[36] Ibid.

Equation 7-3: General Equation for Estimating CH_4 from Post-Mining Activity[37]

Emissions ($MTCO_2e$) = Coal Production (thousand short tons) * Basin Specific Emission Factor (ft^3/short ton) * 18.92 g/ft^3CH_4 * 10^3ft^3/'000 ft^3 * 10^{-6} MT/g * GWP

Exhibit 7-2 below shows a summary of total coal production in Colorado between 2005 and 2019.

Exhibit 7-2: Summary of Colorado Coal Production (Thousand Short Tons/Yr)

Thousand Short Tons/Yr	2005	2010	2015	2019
Underground Mine Production	28,439	20,085	13,141	9,316
Surface Mine Production	10,071	5,078	5,738	3,552
Total Coal production	38,510	25,163	18,879	12,868

Methane is released from abandoned underground coal mines, with the quantity emitted dependent on the time since abandonment, the degree to which the mine was sealed, and the characteristics of the coal. Emissions are greatest at the time of abandonment and decrease over time. Abandoned mines may have a status of vented, in which all CH_4 is vented freely to the atmosphere, sealed (50%, 80%, or 95% sealed), or flooded (no emissions). Exhibit 7-3 shows the EPA default list of abandoned underground coal mines in Colorado, the year each was abandoned, and the estimated degree of sealing for each. The general calculation method is shown in Equation 7-4 below.

[37] Ibid.

Exhibit 7-3: Abandoned Coal Mines in Colorado[38]

Mine Name	Basin	Year Abandoned	Status	Percent Sealed
Sanborn Creek	Piceance	2003	Sealed	80%
Dutch Creek No 1	Piceance	1992	Sealed	80%
Dutch Creek No. 2	Piceance	1988	Sealed	80%
L.S.Wood	Piceance	1985	Sealed	80%
Coal Basin	Piceance	1981	Sealed	80%
Bowie No 1	Piceance	1998	Venting	
Hawks Nest East	Piceance	1986	Venting	
Bear Mine	Piceance	1982	Sealed	80%
Bear Creek Mine	Piceance	1979	Sealed	80%
Somerset Mine	Piceance	1989	Sealed	80%
Roadside North Portal	Piceance	2000	Sealed	80%
Roadside South Portal	Piceance	2000	Flooded	
Bowie #3	Piceance	2005	Sealed	80%
Thompson Creek No. 1	Piceance	1986	Sealed	80%
Eagle No 5	Piceance	1996	Unknown	
Bear No 3	Piceance	1997	Flooded	
Hawks Nest West	Piceance	1981	Sealed	80%
Rienau No 2	Piceance	1986	Unknown	
Golden Eagle	Raton	1996	Sealed	80%
Allen East & West	Raton	1982	Unknown	
Southfield Mine	Raton	2001	Sealed	80%
New Elk Mine	Raton	1989	Unknown	
King I	Piceance	2009	Sealed	80%

[38] Ibid.

Equation 7-4: General Equations for Estimating CH4 from Abandoned Mines (m3/yr)[39]

$$\text{Vented: } q = qi \times (1 + aT)^{b}$$
$$\text{Sealed: } q = qi \times (1 - c) * (1 + aT)^{b}$$
$$\text{Flooded: } q = qi \times e^{(-DT)}$$

Where,

q = current emission rate, m^3/yr
qi = emission rate at abandonment, m^3/yr
a = constant unique to each decline curve
b – constant unique to each decline curve
T = time since abandonment, yr
c = degree of sealing of the mine (50%, 80%, or 95%)
D = decline rate, fraction per year (given as -0.672)

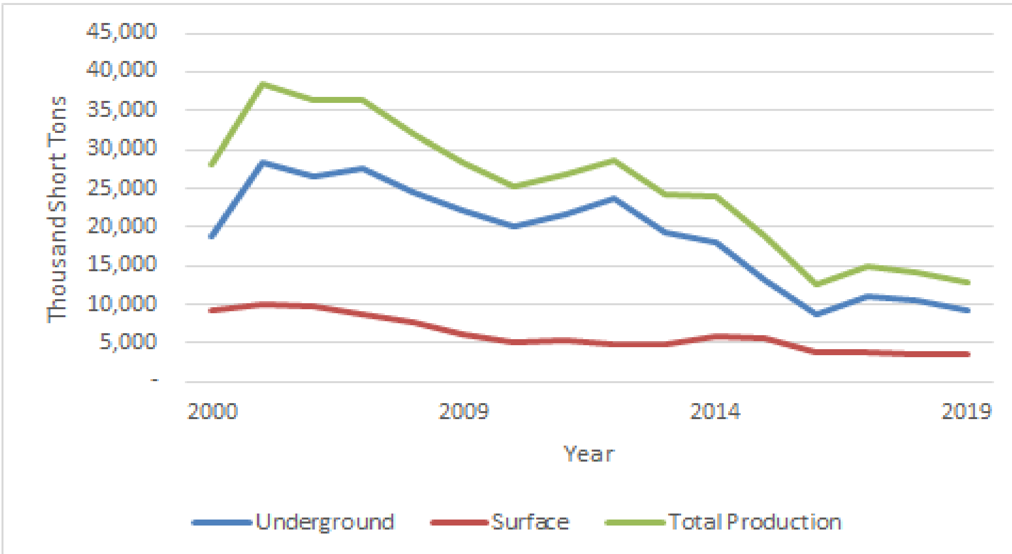
7.4. Emission Trends

Coal is produced from both underground and surface mines in Colorado, with the majority produced from underground mines. Exhibit 7-4 shows coal production in Colorado from 2000 to 2019,[40] which has been gradually decreasing since 2005. The graph shows both total production and the distribution between production from underground and surface mines.

[39] Ibid.

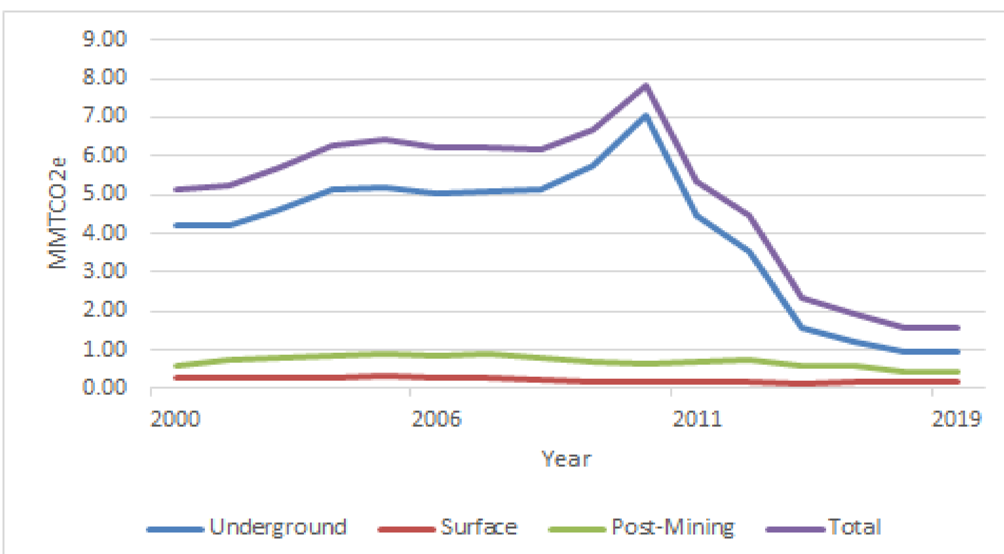
[40] U.S. EPA. State Inventory Tool, Methane Emissions from Coal Mining Module (October 1, 2017) and U.S. Energy Information Administration (EIA) Annual Coal reports, 2016 - 2019.

Exhibit 7-4: Colorado Coal Production



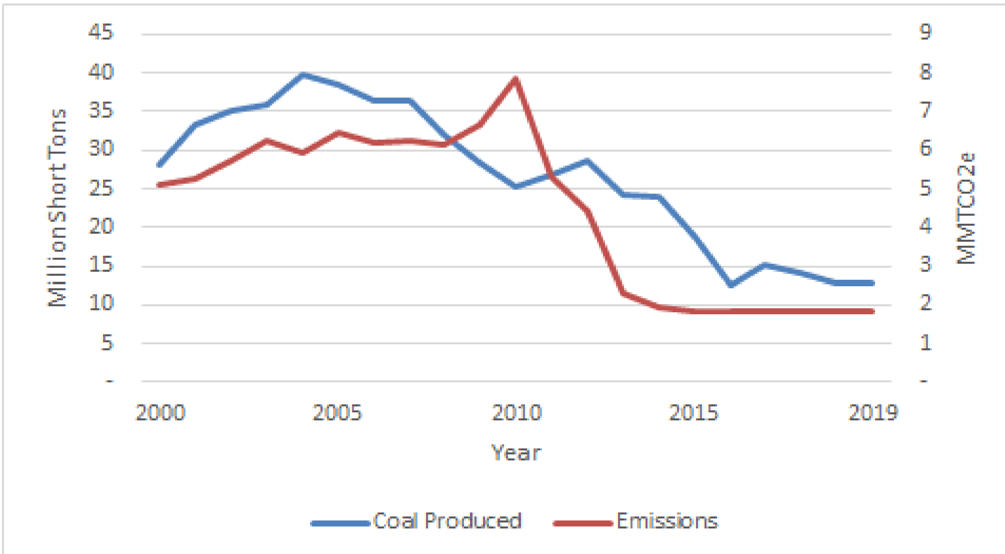
Methane is emitted from several activities in the coal mining sector. These include underground mining, surface mining, and post-mining activities, such as loading and transporting coal. The distribution of CO_2e emissions is shown in Exhibit 7-5 by mine type. It is readily apparent from the graph that the majority of emissions are generated from underground mining, which have decreased significantly since 2010 along with total emissions.

Exhibit 7-5: Emissions from Coal Mining ($MMTCO_2e$)



Between 2010 and 2019 there was a significant decrease in coal mining activity in Colorado. Exhibit 7-6 compares coal production and emissions from 2000 to 2019.

Exhibit 7-6: Coal Production vs. Emissions ($MMTCO_2e$)



Emissions are largely determined by underground mining activity, as shown in Exhibit 7-5. Overall emissions are closely tied to coal production from underground mines, though they do not track exactly from year to year. Emissions from underground mines are primarily from ventilation and degasification, and are affected by specific mining operations, such as opening a new area of a mine. Over a longer time period, emissions generally follow the trend of production from underground mines. Between 2012 and 2015 some additional methane recovery was reported, further reducing emissions. Assuming coal production continues to decline in future years, emissions are also likely to continue to decline.

7.5. Uncertainties Associated with Emission Estimates for the Coal Mining Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with this module assessing GHG emissions from the Coal Mining sector. Uncertainty exists in each category – mining, post-production activities, and abandoned mines, primarily in the emission measurements and factors used. Estimates of emissions from ventilation systems are based on actual measurement data and thus are considered to have a low level of uncertainty. Similarly, estimates of emissions from degasification systems have low uncertainty, mostly due to potential errors in determining the size of each well's drainage area. Surface mining and post-mining emissions have a greater level of uncertainty due to inherent inaccuracies associated with developing emission factors from field measurements.

8. NATURAL GAS AND OIL PRODUCTION

8.1. Overview

The Natural Gas and Oil Production sector includes estimated fugitive methane (CH_4) emissions from the extraction and production of natural gas and oil, and carbon dioxide (CO_2) emissions from venting and flaring natural gas. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Natural Gas and Oil sector accounted for approximately 17% of Colorado's GHG inventory in 2019.

Unlike other sectors within the inventory that primarily rely on the SIT model for estimating emissions, emissions from the natural gas and oil production sector were estimated based on the Division's analysis of natural gas and oil production emissions in Colorado. This analysis was also used to establish the 2005-year baseline for oil and gas production emissions to compare against mandated GHG reductions under HB 1261.

8.2. Analysis and Results

Due to the limitations and uncertainties of the SIT and to account for regulatory initiatives undertaken by the state of Colorado since 2005 to address oil and gas emissions, along with results from flyover studies of methane emissions from oil and gas production, the Division conducted a detailed analysis to provide a more refined estimate of emissions from oil production and natural gas production and delivery in Colorado for use in the GHG Roadmap and this inventory.

The Division believes that its analysis provides a more accurate assessment of natural gas and oil production emissions than the SIT. The SIT relies on a broad and generalized approach to estimating emissions that is not specific to Colorado and does not account for differing emission rates based on specific activities, specific types and quantities of equipment, actual rates of production, and regional differences in oil and gas characteristics. For example, for natural gas wells, the SIT estimates emissions using the number of producing gas wells in the state, but not actual production from those wells, and a regional emission factor per well that applies to all wells in the Rocky Mountain region states.[41] For oil wells, the SIT uses a national emission factor. Additionally, the SIT does not account for regulatory actions to reduce oil and gas emissions, which the state of Colorado has undertaken numerous times since 2005.

Exhibit 8-1 shows annual oil and natural gas production in barrels (bbl) and million standard cubic feet (mmscf), respectively, along with total estimated emissions in

[41] Arizona, Colorado, Idaho, Montana, Nevada, North Dakota, South Dakota, Utah, and Wyoming

MMT of CO_2e in Colorado based on the Division's analysis. Emissions of CH_4 are converted to CO_2e using a global warming potential factor.

Exhibit 8-1: Oil and Gas Production and Estimated CO_2e Emissions

Year	2005	2010	2015	2019
Oil Production (bbl)	23,231,127	33,065,654	123,370,828	194,197,784
Natural Gas Production (mmscf)	1,155,827	1,662,419	1,690,885	1,990,520
Total Emissions (MMTCO2e)	20.166	28.899	19.648	21.930

8.3. Data and Methodology

To assess natural gas and oil production emissions from 2005 and on, the Division's analysis used a combination of state-level inventory data, production data from the Colorado Oil and Gas Conservation Commission (COGCC), type of well drilled (vertical vs horizontal), engineering design analyses such as stages of separation and use of tankless systems at well production facilities, natural gas sampling analyses, estimates of flaring and venting rates, regulatory reach and effectiveness, and methane "catchall" leak-rate fluxes derived from top-down flyover studies of methane in oil and gas basins conducted in Colorado and elsewhere.

8.3.1. Natural Gas Production and Emissions

For natural gas production, the Division utilized monthly production data by county provided through the Colorado Oil and Gas Information System (COGIS) of the COGCC (see Exhibit 8-1 for annual natural gas production). For natural gas emissions and estimated leak rates, the Division relied on natural gas sampling data from around the state, emission factors developed for the 2014 AQCC oil and gas rulemaking, and CH_4 flyover study data. The Division also accounted for oil and gas rule reach and effectiveness based on the number of facilities statewide affected by adopted rules and their impact in reducing emissions. Colorado has added requirements, beginning in 2014, for leak detection and repair (LDAR) programs, replacement of many pneumatic devices with low-or no-bleed devices, and other measures to decrease hydrocarbon emissions, including emissions of CH_4.[42] The Division assumes a statewide upstream "catchall" leak rate of 4% up through 2014 when LDAR requirements were first adopted, which decreases to an assumed rate of 2.5% beginning in 2015 when the LDAR requirements were first implemented, and then to 2.4% beginning in 2018 when additional methane control requirements became

[42] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, 5 CCR 1001-9.

effective. The Division assumes a downstream of the gas plant "catchall" leak rate of 0.5% throughout the historical period, which is projected to decrease in the future.

Note that the Division's analysis does not account for emission sources at natural gas processing facilities, although combustion emissions from oil and gas operations are captured under the RCI sector (see chapter 4). The Division's analysis does estimate emissions downstream of a gas plant such as from the gas distribution system. Data sources for this include gas loss reporting from the Public Utilities Commission (PUC) and EPA GHG Reporting Program data for transmission compressor stations. Availability of additional GHG emissions data for other downstream sources and gas processing plants will be available beginning in mid-2021 and 2022 through the inventory reporting requirements for the oil and gas sector under AQCC Regulation No. 7 (Reg 7). These reporting requirements will also apply to numerous sources upstream of a gas plant.

Note that the 2019 inventory report based on the SIT model does not include transmission and distribution emissions including from gas processing plants and distribution pipelines due to the model not providing default input data to estimate emissions for this particular sector in oil and gas.

Venting and flaring of natural gas is a safety practice that results in GHG emissions to the atmosphere. This is separate from equipment leaks or fugitive emissions. Venting can occur in all phases of oil and gas production and transmission, including during the well completion process, from storage tanks at production facilities, and from pipelines for safety or maintenance purposes. The Division estimated rates of venting and flaring of natural gas in its analysis but due to limited data for some activities, such as pipeline blowdowns and pigging, relied on flyover data to help better inform its analysis. For other types of venting, such as from storage tanks at well production facilities, the Division was able to make more refined estimates based on production, type of well drilled (vertical/horizontal) and facility design such as stages of separation for the oil and gas or use of tankless systems. Similar to what is noted above regarding emissions at and downstream of a gas plant, many sources of venting will be captured under the oil and gas inventory reporting requirements of Reg 7 beginning in 2021 and 2022. Additionally, recently adopted rules by the COGCC will forbid routine venting and flaring in Colorado.

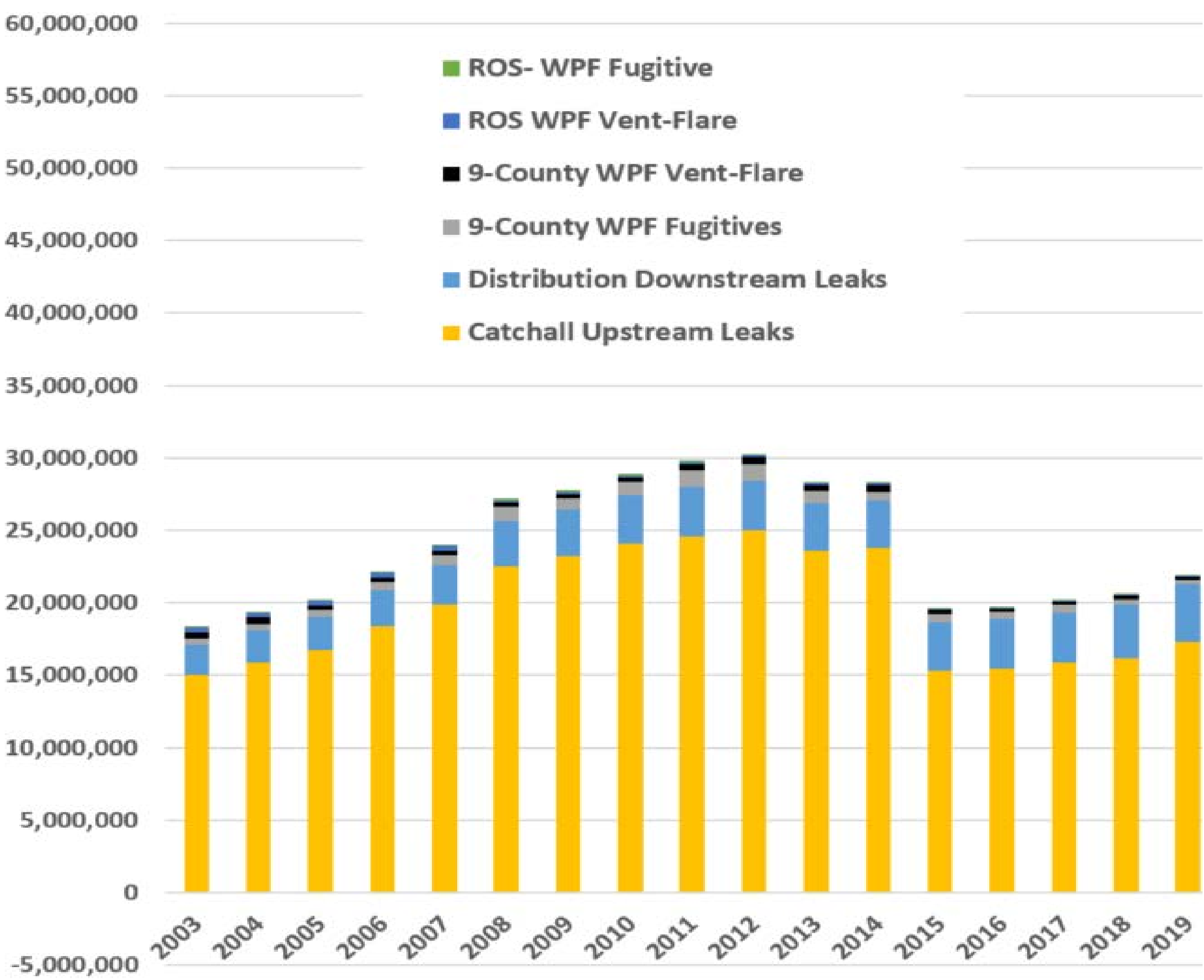
8.3.2. Oil Production and Emissions

Similar to how natural gas production was determined, the Division relied on monthly oil production data available through COGIS (see Exhibit 8-1 for annual oil production). To calculate emissions from oil production, the Division utilized emission factors developed by the Division's Oil and Gas Team engineering unit, storage tank counts at well production facilities, emissions capture and control efficiencies for storage tanks (for example, 95% flare destruction efficiency), as well as rule reach and effectiveness for storage tank requirements. The Division first implemented regulatory storage tank control requirements under Reg 7 beginning in 2005 that were expanded through additional rulemakings by the AQCC over the years. Much of the oil production emissions are based on the storage tank venting calculations discussed in subsection 8.3.1 above, which rely on the type of well drilled (vertical/horizontal) and stages of separation or use of tankless systems.

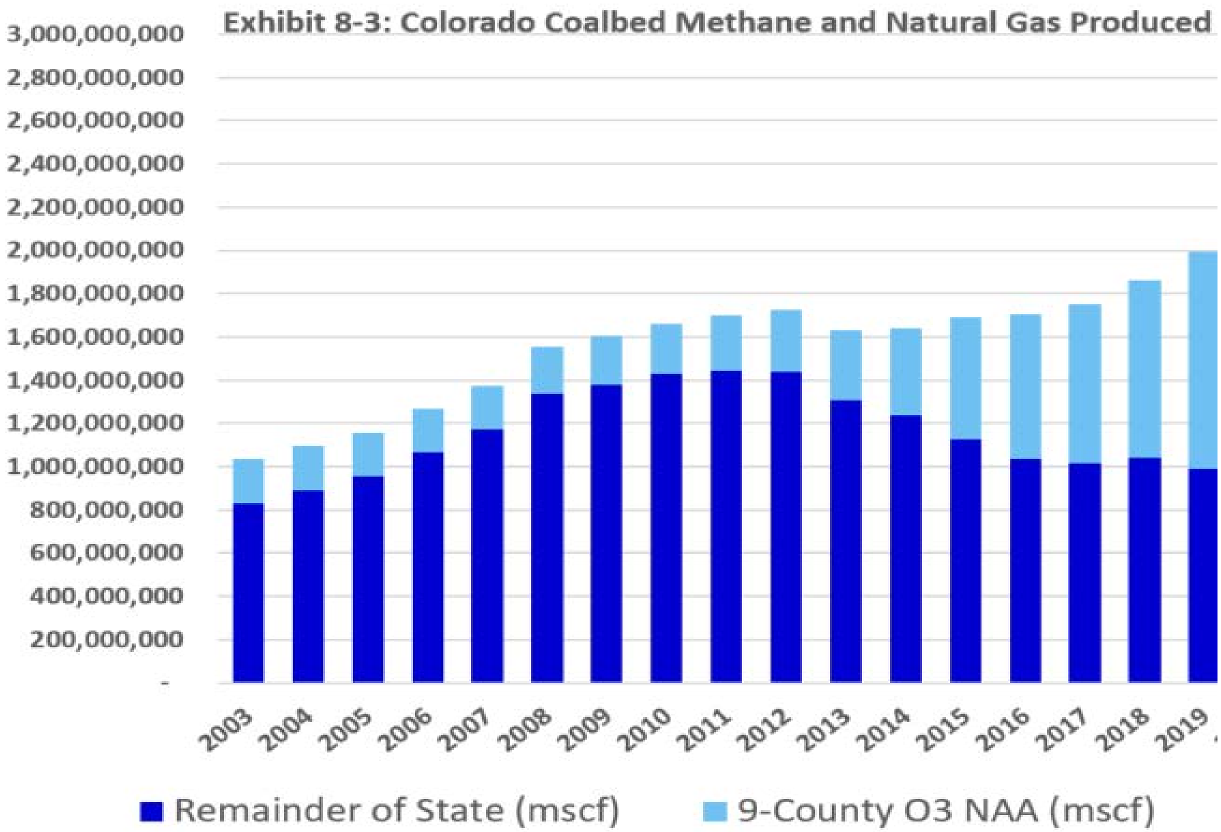
8.4. Production and Emission Trends

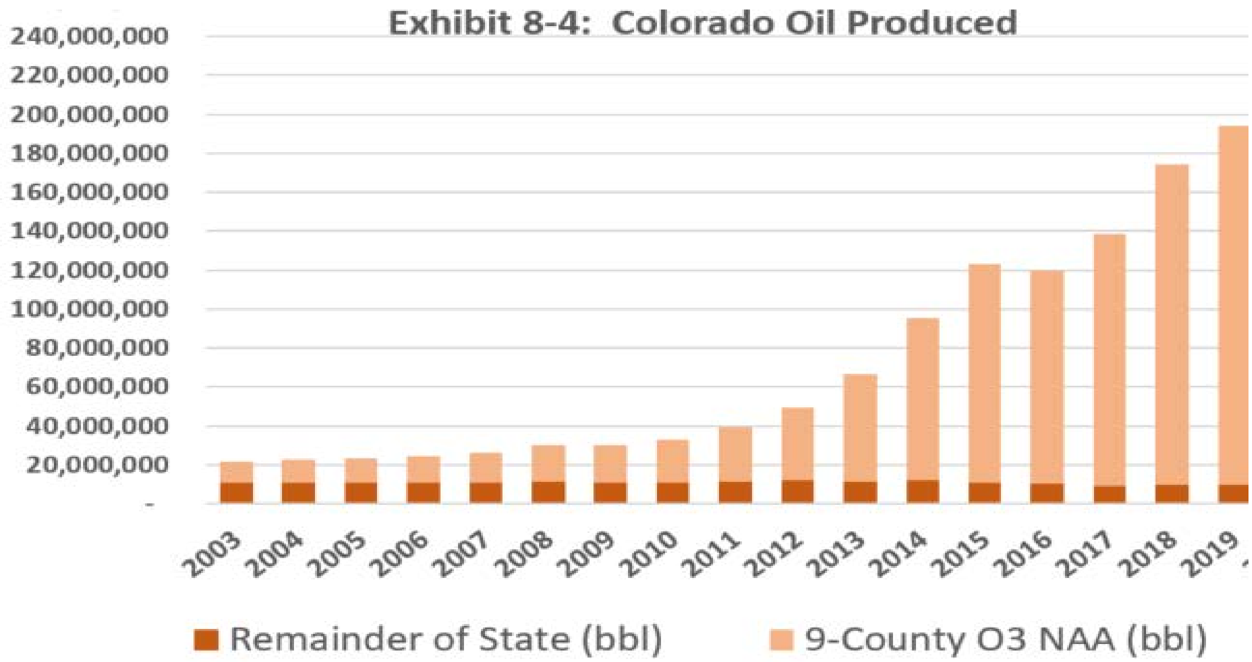
The majority of GHG emissions from oil and gas systems are generated from leaks. Exhibit 8-2 shows the total estimated GHG emissions from oil and gas production and the emissions contributions from various sources on an annual basis from 2003 to 2019 (ROS = Rest of State; 9-County = Ozone Nonattainment Area; WPF = Well Production Facility). As noted, the majority of emissions result from upstream and downstream leaks in the oil and gas sector.

Exhibit 8-2: Oil & Gas Total CO2e Emissions in Metric Tons



Emissions from both oil and gas production are related to production rates, which increased significantly in the state from 2003 to 2019. During that period, gas production increased by 92% while oil production increased by almost ninefold as can be seen in Exhibits 8-3 and 8-4 (O3 NAA = Ozone Nonattainment Area). Notably, though, emissions did not increase at the same rate as production, primarily owing to regulatory actions taken by Colorado to reduce emissions from oil and gas production during that time. Although emissions increased steadily from 2005 to 2014, they began to decrease in 2015 and are estimated to have increased by only 9% from 2005 levels by 2019 (see Exhibit 8-2).





8.5. Uncertainties Associated With Emission Estimates for the Natural Gas and Oil Production Sector

As with the SIT modules used to generate emissions for other sectors in this inventory, there are also uncertainties associated with the Division's analysis of natural gas and oil production emissions in Colorado. Many of the uncertainties are associated with limited data availability, primarily on the natural gas production side. For example, there is a lack of information on the number of blowdowns and piggings (pigging is the practice of using a pipeline device generally referred to as a pig to perform various safety and maintenance operations, which results in emission releases when the pig is launched and received in the pipeline) that occur on an annual basis. Similarly, there is limited data on emissions venting resulting from completions and recompletions of wells. To help address some of these uncertainties, the Division relied on the results of several flyover studies of methane emissions in oil and gas basins, including in Colorado.

For future inventory data related to oil and gas production, the Division will have more specific and detailed information on numerous sources of emissions as a result of the oil and gas inventory reporting rule under Reg 7, which applies to upstream and downstream operations. The first reported data for upstream operations is due in mid-2021 and for downstream operations in 2022. This data will result in a more robust inventory of emissions from the natural gas and oil production sector.

9. AGRICULTURE

9.1. Overview

The Agriculture sector includes estimated methane (CH_4) and nitrous oxide (N_2O) emissions resulting from livestock and crop production in Colorado. There are four broad categories of emission sources within the Agriculture sector: livestock enteric emissions (flatulence); manure emissions; emissions from agricultural soils; and emissions from crop residue burning. Direct carbon dioxide (CO_2) emissions from farm equipment are reflected in statewide gasoline and diesel fuel use. All emissions are reported in million metric tons (MMT) of CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Agriculture sector accounted for approximately 8% of Colorado's GHG inventory in 2019.

This version of the inventory covers the years 2005 - 2019. Greenhouse gas emissions from this sector were estimated using the SIT *Methane and Nitrous Oxide Emissions from Agriculture* Module for 2005 - 2015. The Reference Scenario was used to estimate emissions from this sector for 2019.

9.2. SIT Model and Reference Scenario Results

Total estimated Agriculture GHG emissions include CH_4 and N_2O emissions from livestock and crop production activities. Exhibit 9-1 shows the total CO_2e emissions for the Agriculture sector by activity and also shows the emissions by gas and activity.

Exhibit 9-1: Estimated CO_2e Emissions from Agriculture

	2005	2010	2015	2019
Emissions by Category				
Enteric Fermentation	5.314	5.957	6.187	6.187
Manure Management	1.497	1.623	1.843	1.844
Agricultural Soil Management	2.768	2.482	2.625	2.625
Agricultural Residue Burning	0.003	0.006	0.005	0.005
TOTAL EMISSIONS ($MMTCO_2e$)	**9.582**	**10.069**	**10.660**	**10.660**
Emissions by Gas ($MMTCO_2e$)				
CH_4				
Enteric Fermentation	5.314	5.957	6.187	6.187
Manure Management	0.895	1.038	1.202	1.202
Agricultural Residue Burning	0.003	0.005	0.004	0.004
Subtotal CH_4	6.211	6.999	7.392	7.392
N_2O				
Manure Management	0.602	0.586	0.642	0.642
Agricultural Soil Management	2.768	2.482	2.625	2.625
Agricultural Residue Burning	0.001	0.001	0.001	0.001
Subtotal N_2O	3.370	3.069	3.267	3.267

9.3. Data and Methodology

The SIT Agriculture module estimates CH_4 and N_2O emissions from the production of crops and common types of livestock. The model considers emissions from agricultural activities including enteric fermentation (animal flatulence), manure management, agricultural soil management, and crop residue burning. Emissions are calculated based on activity data and default emission factors. The tool provides default livestock population and crop production data and fertilizer use data. Emissions of CH_4 and N_2O are converted to CO_2e using global warming potential factors.

9.3.1. Enteric Fermentation

Emissions from animal-related agricultural sources are estimated based on the animal population and emission factors. The amount of CH_4 produced by livestock depends on the species of animal, whether the animal is a ruminant or a non-ruminant, and its age and weight. Additionally, CH_4 produced varies depending on the quantity and quality of feed consumed. The SIT model utilizes annual average livestock populations. Default regional emission factors are based on categories of the livestock population and regional feed characteristics. Animal species include dairy cattle, beef cattle, swine, sheep, goats, and horses. Less common types of livestock are not included in the model. Cattle are further differentiated based on age and weight. Calves are assumed to produce no enteric CH_4 through six months of age and are omitted from this portion of the module. Emission factors are applied per animal on an annual basis.

Equation 9-1 shows the general method used to estimate CH_4 emissions from enteric fermentation.

Equation 9-1: General Equation for Estimating CH_4 from Enteric Fermentation[43]

Emissions ($MMTCO_2e$) = Animal Population (thousand head) x Emission Factor (kg CH_4/head) x GWP ÷ 10^6 (kg/MMT)

[43] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Agriculture Using the State Inventory Tool (October 2017).

9.3.2. Manure Management

Animal husbandry produces both solid and liquid animal wastes. These wastes may be deposited directly on pastures, ranges, and paddocks, may be spread on fields on a daily basis, or may be stored in a management system and ultimately applied to soils as fertilizer. This part of the SIT model deals with direct CH_4 and N_2O emissions from **storage** of manure from confined animal feeding operations. Emissions are estimated based on animal population data and emission factors. CH_4 is generated as manure decomposes under anaerobic conditions. The quantity of CH_4 generated by livestock manure is based on the quantity of volatile solids (VS), an organic fraction of total solids, in the manure and the maximum CH_4-producing capacity of the manure (B_0). The CH_4-producing capacity of manure depends on the specific composition of the manure, which in turn depends on the composition of the feed. The fraction VS is dependent on the species of animal, and within a species varies with animal age, size, and feed type. There is also some regional variation in B_0 and VS. Default values are provided in the module.[44] The module calculates VS based on the average number of cattle and the average mass of the population of each animal type other than cattle. Equation 9-2 shows the general method used to estimate CH_4 emissions from manure storage.

Equation 9-2: General Equation for Estimating CH_4 from Manure Management[45]

VS Produced $_{\text{Cattle, excluding calves}}$ (kg) = Animal Population (thousand head) x 10^3 x VS (kg/head/yr)

VS Produced $_{\text{Calves and all other livestock}}$ (kg) = Animal Population (thousand head) x Typical Animal Mass (TAM) (kg) x VS (kg/10^3 kg animal mass/day) x 365 (days/yr)

Emissions ($MMTCO_2e$) = VS Produced (kg) x B_0 (m^3 CH_4/kg VS) x MCF x 0.678 kg/m^3 x GWP ÷ 10^9 ($MMTCO_2e$)

B_o = the quantity of CH_4 that can be produced per kilogram of VS in manure

Manure also contains ammonia, which breaks down and is partially converted to N_2O. The module estimates the Kjeldahl nitrogen (K-Nitrogen) excretion rate for each animal type based on head count (cattle) or typical animal mass (TAM) (all other livestock). Kjeldahl nitrogen is the sum of the quantities of organic nitrogen, ammonia, and ammonium ion. Default K-Nitrogen excretion rates are provided for

[44] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Agriculture Using the State Inventory Tool (October 2017).
[45] Ibid.

different types of animals. It is assumed a portion of manure is managed in anaerobic lagoons and liquid systems, and a portion in solid storage, dry lot, and other systems. Through nitrification/denitrification, a portion of the ammonia in the waste is converted to N_2O, and a portion of that volatilizes. Default volatilization factors are provided for liquid storage systems and for dry storage systems. Equation 9-3 shows the general method used to estimate N_2O emissions from storage in manure management systems.

Equation 9-3: General Equation for Estimating N_2O from Manure Management[46]

K-Nitrogen Excreted$_{\text{Cattle, excluding calves}}$ (kg/yr) = Animal Population (thousand head) x 10^3 (head/'000 head) x K-Nitrogen (kg/head/day) x 365 (days/yr)

K-Nitrogen Excreted$_{\text{Calves and all other livestock}}$ (kg/yr) = Animal Population (thousand head) x 10^3 (head/'000 head) x TAM (kg animal mass/head) x K-Nitrogen (kg/10^3 kg animal mass/day) x 365 days/yr)

Emissions ($MMTCO_2e$) = K-Nitrogen Excreted (kg/yr) x Emission Factor (liquid or dry kg N_2O/kg K-N_2) x GWP ÷ 10^9 (kg/$MMTCO_2e$)

Exhibit 9-2 shows Colorado livestock head counts used to estimate enteric fermentation emissions and manure-management emissions for 2005 - 2015. This data was not included in the Reference Scenario so is unavailable for 2019.

[46] Ibid.

Exhibit 9-2: Animal Head Counts (in thousands)

Livestock Type	2005	2010	2015
Dairy Cattle			
Dairy Cows	101	116	145
Dairy Replacement Heifers	50	70	100
Beef Cattle			
Beef Cows	639	714	745
Beef Replacement Heifers	130	120	160
Heifer Stockers	570	500	490
Steer Stockers	840	860	790
Bulls	40	45	55
Calves	130	175	115
Feedlot Heifers	358	332	332
Feedlot Steer	641	622	622
Swine			
Breeding	145	150	145
Market < 60 lb	390	275	240
Market 60-119 lb	95	105	120
Market 120-179 lb	85	70	90
Market 180+ lb	135	130	105
Poultry			
Hens > 1 yr	3,932	3,681	1,132
Pullets	656	1,018	1,235
Chickens	66	53	64
Turkeys	1,186	331	847
Other			
Sheep on Feed	157	177	151
Sheep NOF	208	233	284
Goats	37	40	32
Horses	114	114	109

9.3.3. Agricultural Soils

Through the microbial processes of nitrification and denitrification, N_2O is produced naturally in soils. Agricultural activities add nitrogen to soils, increasing the amount of nitrogen available for these processes, and the amount of N_2O emitted. The sources of N_2O emissions in the Agricultural Soils subsector of the SIT model are divided into three categories: (1) direct emissions from agricultural soils due to nitrogen-fixing crops and crop management practices; (2) direct and indirect emissions from soils from fertilizer application; and (3) direct and indirect emissions from agricultural soils due to animal production.

9.3.4. Nitrogen-Fixing Crops

Some N_2O is emitted in the nitrogen fixation process in plants such as legumes and some forage crops. The SIT model considers the plant residue dry matter fraction, the nitrogen content of the residue, and a default emission factor. N_2O is also emitted from crop residue incorporated into the soil after harvest and any residue burning. The model considers the plant residue dry matter fraction, the nitrogen content of the residue, and the fraction of the residue incorporated into the soil for a variety of crops. The model also includes calculations for a variety of forage crops, but does not provide default production data for these crops. Equations 9-4 and 9-5 show the general methods used to estimate N_2O emissions from the production of nitrogen-fixing crops and from crop residues.

Equation 9-4: General Equation for Estimating N_2O from Nitrogen-Fixing Crops[47]

Emissions ($MMTCO_2e$) = Crop Production (MT) x Mass Ratio (residue/crop) x Dry Matter Fraction x N Content x Emission Factor (1.0%) x 44/28 (Ratio of N_2O to N_2) x GWP $\div 10^6$ (MT/$MMTCO_2e$)

Equation 9-5: General Equation for Estimating N_2O from Crop Residues[48]

Emissions ($MMTCO_2e$) = Crop Production (MT) x Mass Ratio (residue/crop) x Dry Matter Fraction x Fraction Residue Applied x N Content x Emission Factor (1.0%) x 44/28 (ratio of N_2O to N_2) x GWP $\div 10^9$ (kg/$MMTCO_2e$)

Exhibit 9-3 shows the default Colorado crop production data provided in the Agriculture module for 2005 - 2015. This data was not included in the Reference Scenario so is unavailable for 2019. The SIT module includes production data for a limited number of crops. Empty fields in the table indicate a lack of crop production data. This data, along with default emission factors, was used to estimate N_2O emissions from production of nitrogen-fixing crops and from the incorporation of crop residues into the soil.

[47] Ibid.
[48] Ibid.

Exhibit 9-3: Crop Production

Crop Type	2005	2010	2015
Alfalfa ('000 tons)	2,960	2,870	2,870
Corn for Grain ('000 bushels)	140,600	182,710	134,900
All Wheat ('000 bushels)	54,035	103,350	81,485
Barley ('000 bushels)	7,670	8,379	8,190
Sorghum for Grain ('000 bushels)	3,410	7,520	22,000
Oats ('000 bushels)	1,125	910	800
Rye ('000 bushels)	-	-	-
Millet ('000 bushels)	5,500	7,095	8,970
Soybeans ('000 bushels)	-	-	-
Peanuts ('000 lbs)	-	-	-
Dry Edible Beans ('000 hundredweight)	1,095	1,254	846
Dry Edible Peas ('000 hundredweight)	-	-	-
Austrian Winter Peas ('000 hundredweight)	-	-	-
Lentils ('000 hundredweight)	-	-	-
Wrinkled Seed Peas ('000 hundredweight)	-	-	-
Sugarcane ('000 tons)	-	-	-

9.3.5. Fertilizer

This section of the SIT model estimates direct and indirect N_2O emissions from land application of synthetic and non-manure organic nitrogen-based fertilizer. Emissions from manure used as fertilizer are discussed separately. Direct emissions are estimated based on the unvolatilized quantity of fertilizer applied to the land. Indirect emissions are estimated based on the quantity of nitrogen which volatilizes as NH3 or NOx and is then converted to N_2O and emitted. Direct emissions are estimated based on the quantity of fertilizer used, the nitrogen content of the fertilizer, an estimate of the quantity of nitrogen lost to volatilization as NOx or NH3, and a default emission factor. A separate default emission factor is applied to the portion of the volatilized NH3 and NOx that is converted to N_2O and emitted. Manure use is subtracted from total organic fertilizer and addressed in the section on management of agricultural soils associated with livestock production, as are indirect emissions from leaching. Equations 9-6 and 9-7 show the general methods for estimating direct and indirect emissions from synthetic and non-manure organic fertilizer use.

Equation 9-6: General Equation for Estimating __Direct__ N_2O Emissions from Agricultural Soils[49]

Emissions ($MMTCO_2e$) = Total N_2 (kg) x fraction unvolatilized (0.9 synthetic or 0.8 organic) x 0.01 (kg N_2O/kg N_2) x 44/28 (ratio of N_2O to N_2) x GWP ÷ 10^9 (kg/$MMTCO_2e$)

Equation 9-7: General Equation for Estimating __Indirect__ N_2O Emissions from Agricultural Soils[50]

Emissions ($MMTCO_2e$) = Total N_2 (kg) x fraction volatilized (0.1 synthetic or 0.2 organic) x 0.001 (kg N_2O/kg N_2) x 44/28 (ratio of N_2O to N_2) x GWP ÷ 10^9 (kg/$MMTCO_2e$)

9.3.6. Agricultural Soils and Animal Production

This section of the SIT model considers direct and indirect emissions of N_2O from the land application of manure. The model assumes that all manure is eventually applied to agricultural soils. Direct emissions are attributed to daily spread operations, application of manure from management systems, and animal wastes that are deposited directly on soils by animals in pastures, paddocks, and ranges. Indirect emissions are attributable to volatilization, leaching, and run-off.

The module uses animal population data and default K-Nitrogen excretion factors to estimate the amount of nitrogen in manure. Default emission factors are then applied to estimate direct and indirect emissions. A portion of the nitrogen is volatilized, and default emission factors are applied to the remaining nitrogen to estimate N_2O emissions from daily spread, manure from management systems, and manure deposited directly on pastures. Indirect emissions from leaching and run-off are assumed to occur from 30% of the total unvolatilized nitrogen. A portion of the unvolatilized nitrogen is emitted directly from manure from management systems applied to soils, manure applied to soils as daily spread, and manure deposited directly on pastures, ranges, and paddocks. A portion of the nitrogen is volatilized, converted to N_2O, and emitted as indirect emissions from daily spread, manure from management systems, and manure deposited directly on pastures.

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[49] Ibid.
[50] Ibid.

9.3.7. Agricultural Residue Burning

After harvest, some portion of crop residue may be burned. The SIT tool estimates CH_4 and N_2O emissions from the burning of agricultural residue based on crop production, crop/residue ratio, proportion of residue burned, proportion of dry matter in the residue, burning efficiency (how much of the residue burns), and combustion efficiency (how completely the residue is oxidized). Emission factors are applied to the total mass of plant residue burned to estimate CH_4 and N_2O emissions. Equation 9-8 shows the general method used to estimate emissions from agricultural residue burning.

Equation 9-8: General Equation for Estimating CH_4 and N_2O Emissions from Agricultural Residue Burning[51]

Emissions ($MMTCO_2e$) = Crop Production (MT) x Residue/Crop Ratio x Fraction Residue Burned x Dry Matter Fraction x Burning Efficiency x Combustion Efficiency x C or N Content x Emission Ratio (CH_4-C or N_2O-N) x mass Ratio (CH_4/C or N_2O/N) x GWP ÷ 10^6 (MT/$MMTCO_2e$)

9.4. Data Uncertainties

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with the module assessing GHG emissions from the Agricultural sector. Estimation methods for this sector use a large quantity of activity/production data and a large number of emission factors. There is considerable uncertainty in each of these areas. Some of the specific uncertainties associated with this module are discussed below.

Animal populations fluctuate throughout the year. There is uncertainty in the original population survey methods, and in the single average population number used in the model for each type of animal. In addition, the model does not account for the production of less common livestock, such as bison and llamas. Emission factors and K-Nitrogen excretion factors vary depending on diet and the specific animal.

There is a lack of specificity of manure management systems in the state. Colorado has confined animal feeding operations for swine and poultry as well as open range animal production. Emissions from management systems vary depending on how long the manure is stored. Manure quantity and characteristics also vary considerably by animal type, size and feed characteristics. National default emission factors may not be reflective of Colorado animal production. For example, Colorado's regulations for

[51] Ibid.

swine often require manure to be stored in covered, rather than open, lagoons, resulting in decreased emissions.

The key emission associated with soil management is N_2O release. Factors of nitrogen input from fertilizers, soil moisture, pH, and other variables dictate how much N_2O is produced. Emission factors do not take into account specific soil, climate, and management conditions. Quantities of crop residue left on fields is estimated, as there is no data available. There has been limited research on nitrogen-fixing in different crops and conversion factors may not adequately account for the variety of conditions across the state.

Emissions of N_2O due to leaching and run-off are relatively uncertain due to uncertainty of the volatilization rates and the proportion of leached nitrogen. The quantity of crop residue burned is not well-documented, introducing another area of uncertainty to the estimation calculations.

10. WASTE MANAGEMENT

10.1. Overview

The Waste Management sector includes estimated direct CH_4 emissions from municipal landfills, CO_2 and N_2O emissions from the combustion of solid waste, and CH_4 and N_2O emissions from the treatment of municipal and industrial wastewater. All emissions are reported in million metric tons (MMT) of CO_2 or CO_2 equivalent (CO_2e). The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1. Emissions from the Waste Management sector accounted for approximately 3% of Colorado's GHG inventory in 2019.

This version of the inventory covers the years 2005 - 2019. Two modules from the SIT model were used to estimate greenhouse gas emissions for 2005 - 2015 from this sector – *Municipal Solid Waste* and *Wastewater.* The Reference Scenario was used to estimate emissions from this sector for 2019.

10.2 SIT Model and Reference Scenario Results

Total estimated Waste Management GHG emissions include CH_4 emissions from landfilling of municipal solid waste and CH_4 and N_2O emissions from municipal and industrial wastewater treatment. Exhibit 10-1 shows the SIT modules and Reference Scenario results for the waste management sector, and the combined total estimated CO_2e emissions for the sector.

Exhibit 10-1: Estimated Waste Management Emissions

Emissions ($MMTCO_2e$)	2005	2010	2015	2019
CH_4 Emissions from Landfills ($MMTCO_2e$)				
MSW Generation	2.262	3.113	3.833	NA
Industrial Generation	0.158	0.218	0.268	NA
Subtotal - Potential CH_4	2.421	3.331	4.101	NA
CH_4 Avoided - Flare	(0.424)	(0.037)	(0.037)	NA
CH_4 Avoided - Landfill Gas-to-Energy	0.000	0.000	(0.154)	NA
Oxidation at MSW Landfills	(0.184)	(0.308)	(0.364)	NA
Oxidation at Industrial Landfills	(0.016)	(0.022)	(0.027)	NA
Total Emissions from Landfills	1.797	2.964	3.519	3.701
CH_4 and N_2O Emissions from Wastewater ($MMTCO_2e$)				
Municipal CH_4	0.373	0.404	0.436	0.458
Municipal N_2O	0.142	0.150	0.167	0.176
Industrial CH_4	0.053	0.065	0.065	0.068
Total Emissions from Wastewater	0.568	0.619	0.668	0.668
CH4 and N2O Emissions from Waste Management				
CH_4	2.224	3.433	4.020	4.227
N_2O	0.142	0.150	0.167	0.176
Total Waste Management ($MMTCO_2e$)	2.366	3.583	4.186	4.403

10.3 Data and Methodology

The SIT Municipal Solid Waste (MSW) module estimates CH_4 emissions from landfilling of municipal solid waste and CO_2 and N_2O emissions from municipal solid waste combustion. The Wastewater module estimates CH_4 and N_2O emissions from the treatment of wastewater. Emission estimates are based on activity data, such as quantity of waste landfilled and wastewater treated, and default emission factors. Emissions of CH_4 and N_2O are converted to CO_2e using global warming potential factors.

10.3.1 Municipal Solid Waste

The estimated CH_4 emission rate from landfills is a function of the quantity of waste landfilled over the previous 30 years. The SIT tool provides default waste disposal data from the allocation of national data to the state level on the basis of the state's historical population, and emission factors based on a first order decay statistical model. Organic waste in landfills is decomposed by microbial processes, generating a biogas containing approximately equal parts CH_4 and CO_2. The source of these gases is primarily the decomposition of organic materials derived from biomass sources such as crops and forests, which are grown and harvested sustainably, removing CO_2 from the atmosphere at the same rate it is added. Some landfills flare recovered biogas, converting the CH_4 portion to CO_2. There was insufficient biogas-to-energy data to include this category for Colorado for 2005 to 2015. Neither the CO_2 emitted directly as a biogas nor the CO_2 emitted from combusting CH_4 is counted as an anthropogenic greenhouse gas emission. Carbon storage from landfilled yard trimmings and food scraps is accounted for in the Land-Use and Forestry module, discussed in Chapter 11. There was insufficient data available to evaluate combustion of municipal solid waste in Colorado.

Equation 10-1 shows the first order decay model equation used to estimate the annual quantity of CH_4 generated in landfills. Emissions vary based on the quantity of waste landfilled and the CH_4 generation rate, which is dependent on the climate where the landfill is located (i.e. arid areas generate less CH_4).

Equation 10-1: First Order Decay Model Equation[52]

$$Q_{Tx} = A * k * R_x * L_o * e^{-k(T-x)}$$

Where,

Q_{Tx} = Amount of CH_4 generated in year T by the waste R_{xT}
T = Current year
x= Year of waste input
A – Normalization factor $(1-e^{-k})/k$
k = CH_4 generation rate (yr^{-1})
R_x = Amount of waste landfilled in year x
L_o = CH_4 generation potential, and
e = mathematical constant – Euler's Number

Once CH_4 generation from municipal solid waste landfills is estimated, the quantity is adjusted to include CH_4 generated in industrial landfills. The SIT model uses the assumption that CH_4 generation from industrial landfills is approximately 7% of generation from municipal landfills, based on estimates of the quantity and organic content of waste placed in industrial landfills.[53]

Some portion of the landfill CH_4 may be flared or recovered and combusted to generate electricity. The sIT Waste module assumes that 10% of landfill CH_4 that is not flared or recovered to produce energy is oxidized in the top layer of soil over a

[52] U.S. EPA. User's Guide for Estimating Emissions from Municipal Solid Waste Using the State Inventory Tool (December 2017).
[53] Ibid.

landfill. Total landfill CH_4 generated is reduced by the quantities flared or combusted to produce energy and by the quantity oxidized in the soil, as shown in Equation 10-2.

Equation 10-2: Net CH_4 Emissions from Landfills[54]

Preliminary Net CH_4 Emissions = Total CH_4 Generated – CH_4 Flared or Recovered for Energy – CH_4 Oxidized in Landfill

10.3.2 Wastewater

The SIT Wastewater module estimates CH_4 and N_2O emissions from treated municipal and industrial wastewater. CH_4 is generated when organic material is treated under anaerobic conditions, or when organic material in untreated wastewater degrades anaerobically (in the absence of oxygen). The quantity of CH_4 generated is dependent on the quantity of organic material, and is represented by biochemical oxygen demand (BOD), a measurement of the amount of oxygen that would be required to completely consume the organic matter through aerobic decomposition processes. BOD_5 is a standardized measurement of BOD based on a 5-day test. CH_4 emissions are estimated based on state population, estimated BOD_5, the estimated fraction of organic material that is decomposed anaerobically, and an emission factor. Equation 10-3 shows the general calculation method.

The module is able to estimate CH_4 emissions from treatment of industrial wastewater from four industry categories: fruits and vegetables; red meat; poultry; and pulp and paper. Colorado does not have pulp and paper operations in the state and there was insufficient data available to include the other three industrial wastewater sections of the model.

Equation 10-3: Estimated CH_4 Emissions from Municipal Wastewater Treatment[55]

CH_4 Emissions (MMTCO2e) = State Population x BOD_5 Production (kg/day) x 365 (days/yr) x 10^{-3} (metric ton/kg) x Fraction Treated Anaerobically x 0.6 (Gg CH_4/Gg BOD_5) x 10^{-6} (MMT/MT) x GWP

N_2O is generated when nitrogen-rich organic material undergoes natural processes of nitrification and denitrification. Human sewage is believed to constitute a significant portion of the nitrogen-rich organic material in wastewater. N_2O emissions are

[54] Ibid.

[55] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Wastewater Using the State Inventory Tool (October 2017).

estimated based on state population, the portion of the population not on septic systems, which the model assumes is 81%, and an emission factor.[56] The general calculation method is shown in Equation 10-4.

Equation 10-4: Estimated Direct N_2O Emissions from Municipal Wastewater Treatment[57]

N_2O Emissions ($MMTCO_2e$) = State Population x Fraction of Population not on Septic (%) x Emission Factor (g N_2O/person/year) x 10^{-6} (MT/g) x 10^{-6} (MMT/MT) x GWP

N_2O is emitted not only from wastewater treatment processes, but also from the biosolids (sewage sludge) remaining after treatment. The general calculation method estimates the total available nitrogen in wastewater, based on state population, the quantity of protein consumed per capita, and the fraction of nitrogen in protein which is not consumed. The quantity emitted directly from wastewater during treatment is subtracted from this total, leaving just the quantity contained in the biosolids. This quantity is adjusted for the portion of biosolids used as fertilizer and an emission factor is applied to estimate the quantity of N_2O emitted from biosolids during treatment. There is no default data for the quantity of biosolids land-applied as fertilizer in Colorado. Estimated emissions from the use of biosolids as fertilizer would be included in the Agriculture sector. Total N_2O emissions from wastewater treatment are estimated by adding direct emissions to emissions from biosolids. The general calculation method is shown in Equation 10-5.

Equation 10-5: Estimated Total N_2O Emissions from Municipal Wastewater Treatment[58]

N_2O Emissions ($MMTCO_2e$) = [State Population x Protein Consumption (kg/person/year) x $FRAC_{NPR}$ (kg N/kg protein) x Fraction of N not consumed x 0.001 (metric ton/kg) – Direct N Emissions (metric tons)] x [1 – Percentage of Biosolids used as Fertilizer (%)] x Emission Factor (kg N_2O-N/kg sewage N produced) x 44/28 (kg N_2O/kg N) x 10^{-6} (MMT/MT) x GWP + Direct N_2O Emissions

[56] U.S. EPA. State Inventory Tool, Wastewater Module (10/1/2017).

[57] U.S. EPA. User's Guide for Estimating Methane and Nitrous Oxide Emissions from Wastewater Using the State Inventory Tool (October 2017).

[58] Ibid.

10.4 Uncertainties Associated With Emission Estimates from the Waste Management Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with the two modules included in the Waste Management sector. Some of the uncertainties associated with these modules are discussed below.

10.4.1 Uncertainty Associated With the Municipal Solid Waste Module

There are several sources of uncertainty associated with estimating CH_4 emissions from landfills. Waste disposal quantities are based on national data, scaled back down to the state level based on population. This may not accurately represent waste disposal in a specific state. The model assumes a constant proportion of industrial waste relative to municipal waste, which may not be characteristic of a specific state. The methodology also assumes the waste composition of all landfills is the same; it is likely composition varies between landfills.

CH_4 production in a landfill is impacted by temperature, rainfall and landfill design. These characteristics vary for each landfill. The time period over which landfill waste produces CH_4 is also not certain. Little information is available on the amount of CH_4 oxidized during diffusion through the soil cover over landfills; the assumed percent is based upon limited measurements. Additionally, the model does not currently include default data on landfill gas that is recovered and combusted, and thus does not account for the resulting reduction in CH_4 emissions.

10.4.2 Uncertainty Associated With the Wastewater Module

Uncertainty surrounds estimates of CH_4 and N_2O emissions from industrial wastewater treatment. The quantity of CH_4 emissions from wastewater treatment is based upon several factors with varying degrees of uncertainty. For domestic wastewater, the uncertainty is associated with the factor to estimate the occurrence of anaerobic conditions in the treatment systems, based on septic tank usage data. The default estimate of the fraction of the population not on septic is 81%, but that may not be an accurate characterization for the state or for all years from 1990 to 2015. There can be variation in per capita BOD production associated with food consumption, food waste, and disposal characteristics for organic matter, and in the characteristics of individual wastewater treatment plants.

N_2O emissions are dependent upon nitrogen inputs into the wastewater and the characteristics of wastewater treatment methods. The fraction used to represent the ratio of non-consumption nitrogen is another area of uncertainty. The emission factor for effluent is a single default value, based on a range of possible values taken from the IPCC.

Another area of uncertainty is emissions associated with solids generated in the wastewater treatment process. There is a lack of data on the quantity of biosolids applied to land as fertilizer. The model also does not account for different methods of sewage sludge disposal. Some biosolids are land-applied as fertilizer, but some may be incinerated or landfilled.

Though there was insufficient data available to consider industrial wastewaters, wastewater outflows and organic loadings vary considerably for different plants and different sub-sectors (e.g. office paper versus newsprint, or beef versus fish). There can also be variation in the per capita BOD production associated with industrial processes and disposal characteristics for organic matter. There is also variation that can be attributed to characteristics of industrial pretreatment systems.

11. LAND USE AND FORESTRY

11.1 Overview

The SIT Land Use, Land-Use Change, and Forestry (LULUCF) module is unique as it considers the balance between the emission and uptake of greenhouse gases (carbon flux), which affects their atmospheric concentration. The LULUCF module includes CO_2 , CH_4 , and N_2O emissions from fertilization of soils in developed areas (settlement soils), as well as carbon flux from forests, urban trees, landfilled yard trimmings and food scraps, and agricultural soils. The module includes CH_4 and N_2O emission estimates from wildfires, and assumes wildfire CO_2 emissions are captured in overall estimates of forest carbon flux. The LULUCF module no longer estimates CO_2 emissions from Liming of Soils and Urea Fertilization. These categories are now estimated in the Agriculture module for consistency with the Inventory of U.S. Greenhouse Gas Emissions and Sinks.

Emissions of CH_4 and N_2O are converted to CO_2e using global warming potential factors. All emissions and sinks are reported in million metric tons (MMT) of CO_2 or CO_2e. The use of global warming potential factors to express emissions in terms of CO_2e is discussed in Chapter 1.

Emission and sequestration estimates for this sector were generated using the *Emissions and Sinks from Land Use, Land-Use Change, and Forestry* module using EPA-provided default data. The version of this inventory section covers the years 2005 - 2018. For this inventory, additional state-specific wildfire data was added to the LULUCF module, taken from information available in the historical fire statistics on the National Interagency Fire Center website.[59]

11.2 SIT Model Results

Total estimated LULUCF emissions and sinks include CO_2 sequestered, CH_4 and N_2O emitted from urea fertilization, and CO_2 , CH_4 , and N_2O emitted from wildfires and prescribed burns. All emissions are reported in terms of million metric tons of CO_2 or CO_2e. Exhibit 11-1 shows the model results for the LULUCF sector, organized by subcategory of activity from 2005 - 2018. The Reference Scenario estimated this sector as a sink rather than a source of emissions in 2019 similar to the older version of the SIT LULUCF module used for the 2019 inventory. Therefore, to maintain consistency with how this sector's emissions are determined and presented, the Reference Scenario results for this sector are excluded from this inventory.

As noted, the emissions estimates shown in Exhibit 11-1 diverge substantially from those reported for the LULUCF module in the 2019 GHG Inventory Update. The 2019 Inventory Update estimated that the LULUCF sector *sequestered* 6.5 MMTCO2e in

[59] https://www.nifc.gov/fireInfo/fireInfo_statistics.html, Historical year-end fire statistics by state.

2015, while the current analysis estimated *net emissions* from the LULUCF sector of 7.5 MMTCO2e in 2015 and 9.9 MMTCO2e in 2018. This substantial difference is primarily due to methodological changes by the U.S. Forest Service scientists in their estimates of forest carbon flux. Along with several other Rocky Mountain states, Colorado forests are estimated to have become net emitters of greenhouse gases as early as 1990, primarily due to aging forest stands and disturbance.

Exhibit 11-1: Estimated CO2e Emissions/Sinks from Land Use, Land Use Change and Forestry

Emissions (MMTCO$_2$E)	2005	2010	2015	2018*
Forest Carbon Flux				
Aboveground Biomass	16.550	16.987	17.398	17.578
Belowground Biomass	3.604	3.706	3.802	3.848
Dead Wood	(10.266)	(10.444)	(10.597)	(10.631)
Litter	1.113	1.149	1.176	1.169
Soil (Mineral)	(1.234)	(1.253)	(1.269)	(1.291)
Total Wood products and landfills	(0.556)	(0.556)	(0.556)	(0.556)
Subtotal Forest Carbon Flux	**9.211**	**9.590**	**9.954**	**10.116**
Urban Trees	(0.359)	(0.391)	(0.424)	(0.443)
Landfilled Yard Trimmings and Food Scraps				
Grass	(0.008)	(0.012)	(0.012)	(0.010)
Leaves	(0.054)	(0.066)	(0.064)	(0.052)
Branches	(0.050)	(0.062)	(0.060)	(0.049)
Landfilled Food Scraps	(0.061)	(0.051)	(0.047)	(0.046)
Subtotal Yard Trimmings and Food Scraps	**(0.172)**	**(0.191)**	**(0.183)**	**(0.158)**
Forest Fires				
CH_4	0.470	0.417	0.277	2.702
N_2O	0.087	0.078	0.052	0.503
Subtotal Forest Fires	**0.557**	**0.494**	**0.329**	**3.205**
N_2O from Settlement Soils	0.053	0.064	0.059	0.059
Agricultural Soil Carbon Flux	(4.977)	(3.113)	(2.275)	(2.904)
Total (MMTCO$_2$e)	4.314	6.453	7.460	9.875

*Year of latest available data.

11.3 Data and Methodology

As noted, the LULUCF module estimates CO_2, CH_4, and N_2O emissions and CO_2 sequestration from forests, urban trees, landfills, and agricultural cropland and grassland, and takes into account certain emissions from forest fires, and emissions from fertilization of settlement soils. The tool provides default data and emission factors that were utilized although state-specific data was used for wildfire acres burned, which alters the estimate of CH_4 and CO_2 emitted from wildfires.

11.3.1 Forest Carbon Flux

One of the primary building blocks of the module is forest carbon flux. This accounts for the continuous cycling of carbon between ecosystem components and the atmosphere. For example, the growth of trees results in the removal of carbon from the atmosphere and storage in the living trees. When the trees die, decay processes return the carbon to the atmosphere. The net flux is estimated from the sum of carbon fluxes from above and below ground biomass, dead wood, litter, soil carbon, and wood products in use and stored in landfills. The data used in the module is collected from USDA Forest Service sources. Estimates of forest carbon stocks were updated in 2020.[60]

11.3.2 Urban Trees

The urban trees portion of the module estimates the quantity of carbon taken up and stored by trees growing in urban areas. Equation 11-3 shows the general calculation method for estimating carbon sequestration by urban trees.

Equation 11-1: General Equation for Estimating Carbon Sequestration by Urban Trees[61]

Sequestration ($MMTCO_2e$) = Total Urban Area (km^2) x Urban Area with Tree Cover (%) x 100 (ha/km2) x C (Sequestration Factor) (metric tons C/ha/yr) x 44/12 (ratio of CO_2 to C) ÷ 10^6 (MMT/MT)

11.3.3 Landfilled Yard Trimming and Food Scraps

Wastes of biogenic origin, such as yard trimmings and food scraps do not completely decompose when landfilled. The carbon that remains after decomposition is effectively removed from the carbon cycle, and is counted as a carbon sink in this inventory. This portion of the LULUCF module estimates the amount of carbon from yard trimmings and food scraps that is stored in landfills, based on the quantity discarded in a given year, the accumulated material from previous years, and the portion landfilled in previous years that has decomposed. Default data is taken from national data and apportioned to each state based on state population. Equation 11-4 shows the general calculation method for estimating carbon sequestration by landfilled yard trimmings and food scraps.

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[60] U.S. EPA. User's Guide for Estimating Emissions and Sinks from Land Use, Land-Use Change, and Forestry Using the State Inventory Tool (October 2017), and U.S. EPA State Inventory Tool, Emissions and Sinks From Land Use Change and Forestry module (October 1, 2017).

[61] Ibid.

Equation 11-2: General Equation for Estimating Carbon Sequestration by Landfilled Yard Trimmings and Food Scraps[62]

$LFC_{i,t} = \sum W_{i,n} *(1-MC_i) * ICC_i * \{[CS_i * ICC_i] + [(1-(CS_i * ICC_i)) * e^{-kx\,(t-n)}]\}$

where,

t = the year for which carbon stocks are being estimated,

$LFC_{i,t}$ = the stock of carbon in landfills in year t, for waste i (grass, leaves, branches, food scraps)

$W_{i,n}$ = the mass of waste i disposed in landfills in year n, in units of wet weight

n = the year in which the waste was disposed, where 1960 < n < t

MC_i = moisture content of waste i,

CS_i = the proportion of initial carbon that is stored for waste i,

ICC_i = the initial carbon content of waste i,

e = mathematical constant – Euler's Number, and

k = the first order rate constant for waste i, and is equal to 0.693 divided by the half-life for decomposition.

11.3.4 Forest Fires

The forest fires portion of the LULUCF module estimates CH_4 and N_2O emissions from forest fires. Direct CO_2 emissions from forest burning are considered part of the overall forest carbon flux. CH_4 and N_2O emissions from forest burning are included in the state emissions total. The module was run using primarily default data and emission factors. Actual estimated area burned was taken from the National Interagency Fire Center (NIFC) website, historical year-end fire statistics by state, and used for 2005 through 2015. Fire statistics include both wildfires and prescribed fires. Equation 11-5 shows the general calculation method for estimating emissions from forest fires.

[62] Ibid.

Equation 11-3: General Equation for Estimating CH_4 and N_2O Emissions from Forest Burning[63]

Emissions ($MMTCO_2e$) = Area Burned (ha) x Average Biomass Density (kg dry matter/ha) x Combustion Efficiency (%) x Emission Factor (g gas/kg dry matter burned) x GWP ÷ 10^{-6} (Mt/kg) x 10^{-6} (MMT/MT)

11.3.5 N_2O from Settlement Soils

The SIT model assumes approximately 10% of all fertilizers applied to soils are applied to lawns, golf courses, and other landscaping found within settled areas, including developed land, transportation infrastructure, and human settlements, unless they are already included in another category. The calculation addresses N_2O emissions from the application of synthetic fertilizer. The model assumes an emission factor of 1% of the total mass of fertilizer applied annually. Equation 11-6 shows the general method for estimating N_2O emissions from settlement soils.

Equation 11-4: General Method for Estimating N_2O Emissions from Settlement Soils[64]

Emissions (MMTCO2e) = Total Synthetic Fertilizer Applied to Settlement Soils (metric ton N) x Emission Factor (1%)(metric tons N_2O-N/metric ton N) x 44/28 (ratio of N_2O to N_2O-N) x GWP ÷ 10^6 (MMT/MT)

11.3.6 Carbon Soil Flux

Similar to forests, carbon is continuously cycled through croplands, grasslands, and the atmosphere. The amount stored in croplands varies according to crop type, management practices such as rotation, tillage, and drainage, and soil and climate variables. The amount of carbon stored in grasslands varies according to management practices, such as irrigation, and climate. Soil is the primary carbon pool in both types of lands. Emissions or sequestration are estimated based on year-to-year changes in the quantity of carbon stored in croplands and grasslands. Default data is provided.

63 Ibid.

64 Ibid.

11.4 Uncertainties Associated With Emission/Sink Estimates for the Land Use, Land-Use Change, and Forestry Sector

As with all of the SIT modules used to generate this inventory, there are uncertainties associated with the LULUCF module, as discussed below.

Forest carbon flux is a representation of the total non-urban biomass in forested lands. Carbon is captured by growing plants and released when trees and other plants die or burn during wildfires. In the very long term, stasis in the forest mass and sequestration may be a reasonable assumption, however, there is uncertainty in the impact of wildfires on carbon flux in Colorado's forests. The estimated amount of carbon sequestered in above- and below-ground biomass, dead wood, litter, and soil organic carbon is also uncertain.

The key emission associated with soil management is N_2O release. Factors of nitrogen input via fertilization, soil moisture, pH, and other variables dictate how much N_2O is produced. Non-agricultural fertilizer use estimates only include commercial use and crop residue left on soils, which is uncertain and may vary considerably.

The urban tree calculation is based on total urban area in the state and the amount of that area that has tree cover. Due to the highly variable landscaping requirements from development to development, urban tree density is variable and uncertain.

12. GLOBAL WARMING POTENTIAL (GWP) COMPARISON

The 2021 GHG Inventory provides for the first time a comparison of baseline and projected emissions calculated using IPCC AR4 and AR5 GWP values in both 100-year and 20-year time horizons. For consistency across different reporting programs and with national and international protocols, the 2021 inventory continues to use the IPCC AR4 GWP factors mandated by EPA in the Greenhouse Gas Reporting Program (GHGRP)[65] for reporting of historical emissions in the official state inventory and assessment of progress with the goals of HB 1261.

This chapter is meant to be illustrative and provide an overview to compare data that may be reported in various forums using different GWP factors. It is important to note that any comparison of projected emissions using different GWP values, or calculation of GHG percent reductions anticipated in a future year, must also recalculate the 2005 baseline using the same factors for consistency.

12.1 IPCC GWP Values

GWP values are published by the IPCC, which are reviewed, and updated if necessary, with each assessment cycle and set of reports that are released by the IPCC. The most recent publication set is the fifth assessment and the panel is currently working on the sixth assessment, with reports scheduled for publication in 2021-2022. Exhibit 12-1 lists the factors or values for the GHG pollutants included in the comparison for this inventory.

Exhibit 12-1: IPCC AR4 and AR5 GWP Values

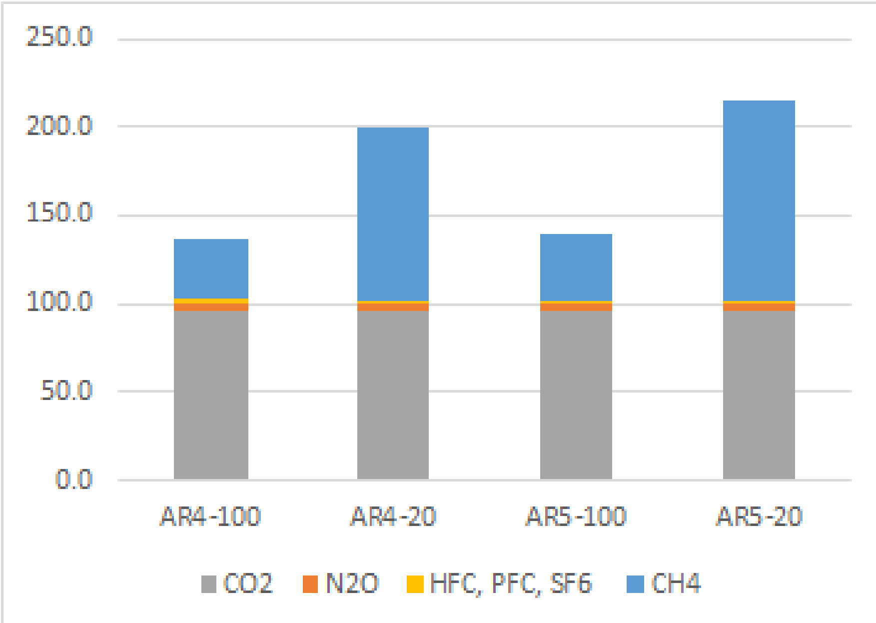
	CO2	CH4	N2O	SF6	NF3	HFCs and PFCs
AR-4, 100 yr	1	25	298	22800	17200	Varies
AR-4, 20 yr	1	72	289	16300	12300	Varies
AR-5, 100 yr	1	28	265	23500	16100	Varies
AR-5, 20 yr	1	84	264	17500	12800	Varies

12.2 Impact of GWP Values on 2005 Baseline

Exhibit 12-2 provides a comparison of Colorado's 2005 GHG baseline emissions, organized by gas, when calculated using 20-year and 100-year time horizon GWP values from the IPCC AR4 and AR5 reports.

[65] 40 CFR 98.2(b)(4) and 40 CFR 98.2 (c)

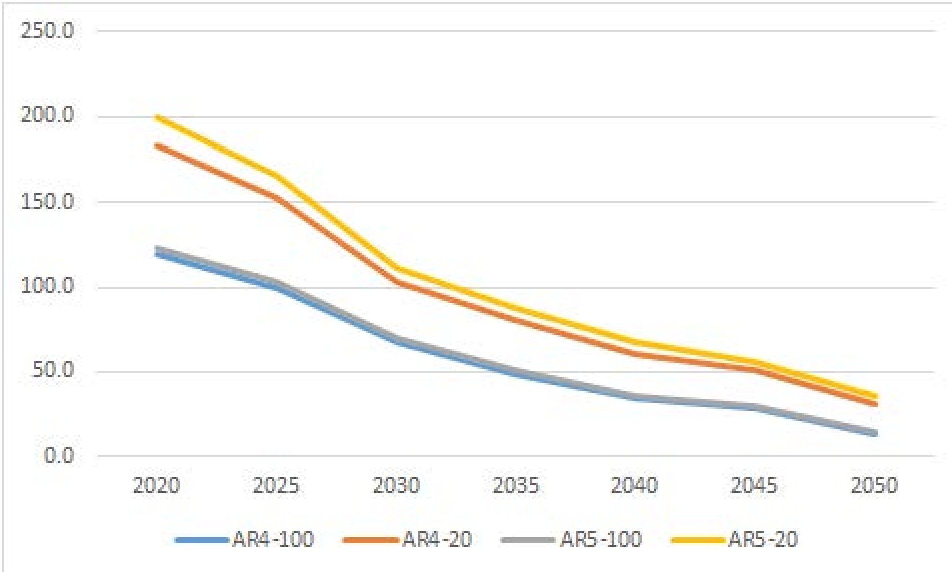
Exhibit 12-2: Estimated 2005 Baseline GHG Emissions using AR4 and AR5 ($MMTCO_2e$)



12.3 Impact of GWP Values on Projections

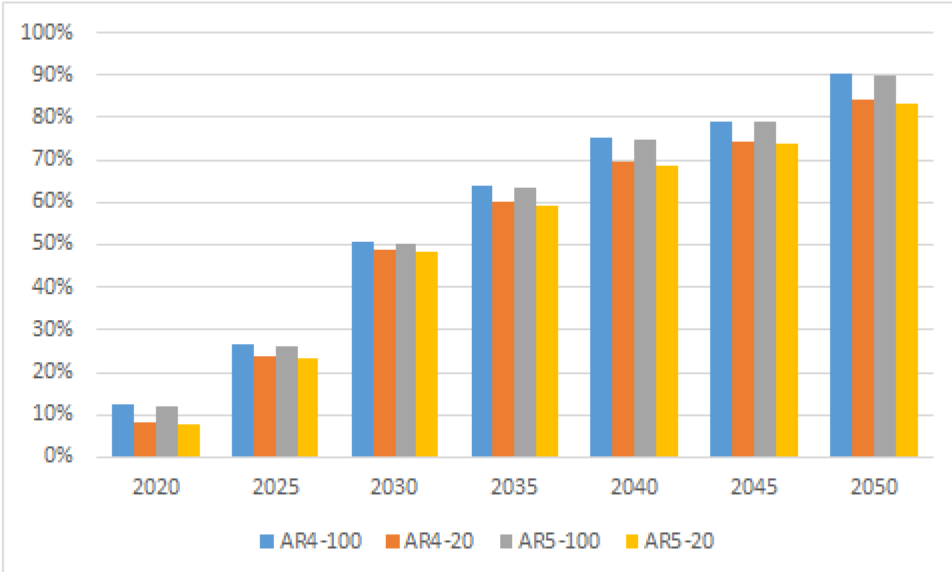
Colorado continues to pursue a comprehensive, economy-wide set of strategies to address GHG emissions. Because of this, the relative trend in reductions is consistent using any of the GWP values. Exhibit 12-3 shows projected emissions from 2020 through 2050 when calculated with the different GWP values.

Exhibit 12-3: Projected GHG Emissions from 2005 Baseline using AR4 and AR5 ($MMTCO_2e$)



Projection estimates in Section 2 show the general trajectory required for the state to secure the statutory goals under HB 1261 using AR4, 100-year time horizon GWP values. Because of the comprehensive strategy being pursued, and the requirement to publish bi-annual inventories that include updated projections, Colorado is well positioned to be able to adjust course and still achieve the goals in HB 1261 in the event that national guidance and international protocols transition to the 20-year time horizon values in the future. Exhibit 12-4 shows projected emissions reduction percentages from the 2005 baseline from 2020 through 2050 when calculated with the different GWP values.

Exhibit 12-4: GHG Percent Reduction from 2005 Baseline using AR4 and AR5



Colorado recognizes the value in consistent reporting with historical data, national guidance, as well as international protocols. Colorado also recognizes that the body of scientific work about the causes and impacts of climate change is growing and evolving. Because of this ongoing work, the current reporting guidance is subject to change in the future. To maintain consistency with current practices, the Colorado GHG Inventory will continue to use AR4, 100-year time horizon GWP values until national and international standards for reporting are revised. Additionally, comparison of the impacts from applying various GWP values to the GHG emissions calculations will be provided to inform the legislative, regulatory, and policy conversations and decisions in Colorado to maintain the trajectory toward the goals established in HB 1261.