# Questions and Answers to Public Comments

## Draft Colorado Greenhouse Gas Inventory

The comments from stakeholders have been summarized below.

### Overarching Comments

1. **Purpose of the GHG Inventory**
   It is unclear how the *Colorado Greenhouse Gas Inventory* will be used.

Response:
The purpose of the inventory is to comply with Executive Order #D 004 08 dated April 22, 2008 by Governor Ritter. The inventory shows progress with the goals established as part of that Executive Order.

2. **Emission Factors**
   *The draft inventory converts methane and nitrous oxide to CO2e using outdated global warming potential values.*

Response:
The national model is geared to be consistent with international GHG reporting agreements, and as such, the Division believes using the weighting factors in the national model helps provide a picture consistent with the national and international standards. At such time as the EPA model and international community elects to update the GWP factors, the Division will use those new numbers.

3. **Population - Census Data vs State Demographer's Office**
   What population data does the inventory use – census data or state demographer data.

Response:
The EPA SIT tool uses a population projection approach inconsistent with the State Demographer's office. This results in a population difference between the SIT Projection tool and the State Demographer's Office of approximately 1.2 million people (state higher) in 2030. Accordingly, all emission calculations

driven by a population figure would be affected by producing greater emissions in 2030 if the State Demographer's Office data were used. Generally, the Demographer's population data from 1990-2010 agrees well with that used in the SIT tools. Several of the SIT modules use population as a factor in the emission calculations. The more significant differences in population begin to emerge in 2009 and 2010. The most significant changes in Projections result from differing population estimates used to calculate the Base Case emissions. As a test scenario, the Division re-ran the EPA SIT model, using the State Demographer's projections to 2030 and 1990-2010 figures. However, certain modules of the EPA SIT model are locked thereby disallowing users the ability to use different population data.

**4. Uncertainties and Limitations with the Model**

Request to have the Division insert a disclaimer to emphasize the uncertainties and limitations model projections.

Response:
The Division addresses uncertainties and limitations with the model throughout the document, but especially in the projection tool.

**5. Energy Production vs Consumption**

The Inventory's estimate of indirect emissions appears to overstate greenhouse gas emissions.

Response:

Several stakeholders noted the disparity in emissions from the Electricity Production Sector with the Electricity Consumption Sector. Based on the model, it appears that Colorado will need to import electricity in the future in order to meet its electricity demands. Currently Colorado does import some power. Future imports will depend on generation fleet and and power demands. The Division has reached out to EPA for further explanation, but at this time this issue is still unresolved.

6. It appears possible there is some double counting occurring in the energy consumption and generation analysis.

Response:
While it may appear double counting is occurring, the electrical generation, based on Colorado reported data, is the only figure used in the inventory to produce the state profile. Consumption figures are provided in accordance with advice from the EPA for informational purposes only. No consumption figures, are used in the total calculations of the final inventory.

7. **Use the Most Current SIT Model.** A revised SIT model has been released since creation of the Draft Inventory.

Response: The division has run all the updated EPA modules release in early 2014. The outputs, compared to the 2013 version, as used in this current draft inventory, are not significantly different. Population figures were updated and the referencing year is now 2011 for comparing Colorado against national data bases. Due to the fact that the Projection tool is not updated, and the significant work that would go into describing the new assumptions and vetting all the data tables, the Division determined not to use the newly released version of the model for this inventory.

## Specific Sectors

## I. Electrical Power

1. The inventory shows an increase in electric power coal consumption. With PSCo's coal plant retirements and no known coal plant additions in Colorado, this number should decrease after 2018. Also, EPA rules that will generally make new coal plant uneconomic should prohibit any coal use increases in Colorado (and elsewhere).

Response:
Figures from 1990 -2010 are based on reported Colorado coal use by electrical generators. Table 'FF Consumption' lists the yearly coal and other fossil fuel used reported to the EIA. Electric power in 1990, generated from coal use, indicates 320,752 Bbtu were consumed. Coal use peaked in 2001 at 386,769 Bbtu and nearly the same in 2006 at 386,389 Bbtu. The model predicts coal use to decline to 352,763 Bbtu in 2030. At the same time natural gas use goes from 13,432 Bbtu in 1990 to 75,265 Bbtu in 2030. The coal use decline from the peak amounts to a 7.8% decrease while natural gas used increased nearly 6 fold. Again, the projected case relies on the 2010 Colorado reported coal and natural gas use for electric power production and the allocation to future use relies on the Annual Energy Outlook 2012 EIA report. National use predictions are allocated back to regions (e.g. Rocky Mountain Region) and the Colorado portion is related to our 2010 portion of that use. The State agrees the coal use likely will not increase, as the model shows, and natural gas use will increase, as the model predicts. The magnitude of the decrease in coal use and increase in natural gas use should be tailored to match Colorado predictions in the next update of the inventory.

2. Does CDPHDE have a coal use/CO2 emissions tracking system for Colorado's coal plants?

Response:
Coal use for electricity production in Colorado is provided to the EIA as part of a series of energy use and production reports done on an annual basis. These reports are used by the EIA to produce State energy use and production profiles on an annual basis. The SIT modules capture this reported data as the basis for emissions calculations. In the post 2013 version of the SIT tool, national reporting data included reported information required by new federal regulations. Future inventory updates will continue to use industry reported data as the basis for emission calculations.

3. In the CO2 Fossil Fuels Combustion spreadsheet under Electric Power - How were the number of billion BTU (e.g. for coal) calculated?

Response:

The *U.S. Energy Information Administration State Energy Data 2011: Consumption* report is the basis for most of the Colorado fossil fuel use data. The Default energy consumption data comes from the EIA *State Energy Data 2010: Consumption Estimates* report. In the $CO_2$ Emissions from Combustion of Fossil Fuels SIT tool this table shows up in the second sub-spreadsheet titled 'Default State Energy Data Table'. The BTU is multiplied by a conversion factor of 55.86 lbs. C/BTU (from 1999 and later; minor deviations from 1990-1998) and this is converted to tones and then to $CO_2$ emissions in MMT. The calculation scheme is laid out in the Fossil Fuel Combustion Guidance document and is discussed in brief in this report.

4. It appears that the calculations end at the end of 2010. This means the calculations won't reflect the addition of the Comanche 3 coal plant in Pueblo in the updated GHG inventory, since Comanche 3 only came on line in mid-2010 and was off line a lot in its first 24 months of operation. This appears to be a significant oversight.

Response:

The *Carbon Dioxide from Fossil Fuel Combustion* SIT tool uses, 'Default state-level data derived from EIA's *State Energy Consumption, Price, and Expenditure Estimates (SEDS) 2010: Consumption Estimates* report which is found at http://www.eia.gov/state/seds/seds-data-fuel-prev.cfm. To the extent industry reported the operations of Comanche 3 to the SEDS data base

this power plant is reflected. Projections of future use are based on a ratio of Colorado's total operations compared to the regional profile and this is compared to the U.S. profile. Future national use projections are then back-allocated to Colorado based on this ratio. In the 2012 SEDS report, Colorado reported 19,199 shorts tons of coal being used for electrical power production (363.6 TBtu). The 2011 SED reported 362.4 TBtu used for electrical Power Coal use in the state, not specific to electrical generation.
Table CT8 of the *U.S. Energy Information Administration State Energy Data* lists the 1960-2011, five year incremental Electric Power Sector Consumption Estimate for Colorado. In this data table both short tons and TBtu are reported. The 2009 coal uses was listed as 17,351,000 short tons (340.5 TBtu); 2010 was listed as 18,979, 000 short tons (369.1 TBtu); and 2011 as 18,744,000 short tons (362.4 TBtu). Based on the 1.63 million ton increase from 2009 to 2010 it appears some major coal consumer was accounted for. However the 2011 numbers indicate a slight drop in coal use for electric power production.

5. The *Colorado Greenhouse Inventory* attempts to break electric consumption GHG emissions down by end use (e.g., air conditioning, heating, appliance, computers, etc.). Are there adequate longitudinal data (1990 to present) from the Residential Energy Consumption (REC) Survey and Commercial Building Energy Consumption (CBEC) Survey to accurately model the end-use breakdown of indirect residential and commercial electric CO2 emissions? Also, some of the trends in end-use breakdown percentages do not seem to reflect changes in technology. For example, both commercial computer and lighting use were flat from 1990 to present?

Response:
The source of the REC and CBEC surveys is a process that started in 1978 and has been repeated thirteen times, providing a longitudinally consistent approach to gathering energy use data in the U.S. The EIA describes the survey procedure in general detail at http://www.eia.gov/consumption/residential/about.cfm and for more specific information one would need to go into the data reports themselves. The projected case relies on the ratio of the Colorado 2010 data to the national information and this percentage is kept constant from 2011-2030. The survey consists of using 12,083 households to statistically represent the 113.6 million U.S. housing units (EIA 2014). The national projection is based on the *Annual Energy Outlook* report and to the extent that the mix of use of energy for the Residential, Commerical and Industrial sectors stays the same, some accounting

for relative energy efficiencies are allocated back to the State. However, the relative sub-category (e.g. A/C, lighting, electrical heat, appliance use, etc.) % breakdown does not change in the SIT projection tool. An improved inventory might consider substituting other projected use distributions into the Projection Case but generating such information may be a significant undertaking for a result that more directional than substantial.

## II. Transportation

1. The Transportation model does not include data on CNG or LNG vehicles.

Response: The CDPHE will consider this in the next update to the inventory.

2. It would be useful to describe whether the state is capable of using the high altitude adjustments (i.e., does the state have this data?).

Response: The APCD does have high altitude adjustments available and will consider using these for the next inventory.

3. Now that EPA has replaced MOBILE with MOVES, MOVES should be the "go to" model for mobile source emissions estimates.

Response: The MOVES Model may be used to estimate emissions in the next Colorado GHG Inventory. APCD considers the current inventory that uses MOBILE6 emissions a base default inventory, and is not a regulatory document as conformity, National Environmental Policy Act (NEPA) or Mobile Source Air Toxics (MSAT) reporting documents are.

## III. Oil and Gas

1. *The draft inventory under-represents Colorado' s well count.* The current draft Inventory for 2010 assumes approximately 29,000 producing wells in Colorado, but 2010 data from the Colorado Oil and Gas Conservation Commission ("COGCC") indicates that there were 45,000 wells in the state. According to the CDPHE, applying the COGCC figures would increase the oil and gas inventory from 6.98 million metric tons CO2e to 10.07 million metric tons CO2e.

Response: The Division agrees that the COGCC well count information indicates a higher well count than the national data base and has adjusted the well count accordingly for the final version of this inventory.

2. Emissions associated with leakage from the natural gas system in Colorado are not included in the inventory, which prevents accounting of reductions from the recent methane emissions rulemaking. Data needed includes:
    - Miles of NG distribution pipeline in Colorado
    - Miles of NG transmission pipelines in Colorado
    - Number of compressor stations in Colorado

Response:

Several options are available for running the O&G module allowing States to tailor their inventory depending on data available to the state. The state had the option of performing the calculations for O&G production and losses during development and distribution based on default assumptions using well counts or state specific data related to miles of pipeline, numbers of compressor stations, and other operational factors.

A more comprehensive view of the emissions could be produced if data for the miles of collector and distribution pipeline was known for each year from 1990-2010. Over the same time the number of compressor stations, developed wells, and storage facilities is needed on an annual basis, along with production figures. Given the complex nature of the data requirements, Colorado opted to run the model in the 'default well count' mode as the other data did not seem to be available. This approach allows the model to calculate emissions based on well counts in the state, using an overall well count and production figure from national data bases.

Colorado agrees that a more comprehensive picture could be generated for the State if yearly data could be obtained covering the factors noted. Preliminary research of Oil and Gas Commission records did not reveal such information is readily, or reasonably, available. The state would use such information in the next inventory update if the industry figures were made available.

3. Future emissions associated with gas production in Colorado could be estimated from a data source that has the estimated recovery of natural gas (MMBTU) in Colorado.

Response:

The Division agrees that future projections of gas production should be based on the best available information. The current draft GHG inventory uses the

2010 production in Colorado compared to the 2010 Rocky Mountain Region production as an anchor point in the projected amount of NG developed (and thus, leaked, to the extent predicted as part of the 'well count' approach).

4. *The draft inventory covers only certain segments of the industry.* The draft Inventory only includes emissions related to natural gas production—leaving unaccounted for emissions from the transmission and distribution segments.

Response: The Division agrees that a comprehensive picture of state emissions related to O&G production might be more reflective if miles of pipeline, numbers of compressor stations and storage facilities, and actual leak and control effectiveness rates were available for past production and projected cases. However, the well count approach takes into account more than estimates of emissions from the well itself as the EF assumes there are miles of leaking pipes, compressor station losses, and storage facility losses associated with the number of wells and productions figures. Without extensive additional data that is not apparently available to the state, the well count approach is the only default options for evaluating emissions from this segment.

5. *Methane emissions from certain sources in Colorado may be higher than the national average values suggest.* For example, liquids unloading occurs more frequently in the San Juan Basin. Also, a recent study by the University of Texas indicates that emissions from intermittent-bleed pneumatic devices may be higher than previous estimates, which could impact emissions estimates in Colorado.

Response: Colorado agrees that the most accurate inventory for Colorado would be based on local factors such as 'liquid unloadings' or better leak rates from pneumatic devices and an accurate accounting of pneumatic device. However, given the nature of the existing data and efforts required to acquire such information, the Division would be unable to complete such an accounting with existing resources. In a future update of the inventory other approaches can be considered if newer, better data is available.
The EPA adjusts emission factors for such things as new leak rate data on an annual basis and such factors should be considered at the national level as well as at the state level.

6. Methane emissions from oil and gas distribution storage tanks and pipelines downstream from processing plants, which were not covered by Regulation #7 rulemaking, should be accounted for.

Response: This may be something that the Division considers in future updates to the GHG Inventory.

7. Does the SIT tool take into account various practices and regulations in the State? For example, those achieved from the recent (2014) revisions to AQCC Regulation Number 7, Oil and Gas Conservation Commission and New Source Performance Standards pursuant to OOOO.

Response:
The default inventory is built on well counts and not on regulated emissions. Future emissions take into account expected national and State rules in some manner. A detailed accounting for the National projections can be found in the Annual Energy Outlook 2012 report on which the 2011 to 2030 projections are based.

Future application of regulatory practices could offset some portion of growth.

8. Does the GHG Inventory account for emission reduction technologies under development?

Response: No accounting for unregulated or unspecified control technologies has been included in either the base case or projected case.

9. The SIT module generally appears to misuse terms that are specific to particular industry segments. The industry segments are "Production, Gathering and Boosting, Processing, Transmission, Storage, and Distribution." If possible, please align these terms with the specific industry segment referenced.

Response: The Division agrees that accurately reflecting industry terms may provide a better understanding of the emission profiles from this segment of the inventory. However, the terms and definitions in the GHG inventory come from the EPA *Users Guide for Estimating Carbon Dioxide and Methane Emissions from Natural Gas and Oil Systems Using the State Inventory Tool* (February 2013). These are used within the SIT model in various sub-sheets. Adding to, or changing the definitions may lead to others outside the industry

being confused by terms within the module, tables, and discussion. However, the Division will attempt to incorporate this suggested language to clarify the emission sources so that practitioners in the industry can better related to the terms.

10. Gas Production, Background, Natural Gas and Oil Systems. "The model considers the four major gas production components industry segments of production, gathering and boosting, processing, transmission, storage and distribution."The Oil and Gas SIT module does not appear to contain emissions from fuel consumption equipment used in the oil and gas industry. These emissions appear to be included in "Residential, Commercial, and Industrial (RCI) Fuel Use." This factor should be made clear and the Division should consider directing readers to portions of that module that are related to oil and gas operations.

Response: Emissions associated with the operation of industrial equipment are reflected in the RCI. However, oil and gas production is not one of the segments covered by that SIT module. Depending on the selection of the default, or state specific options for calculating emissions from oil and gas production, the SIT Oil and Gas tool incorporates operation of equipment. Since the state lacked specific yearly figures for the number of miles of pipeline, compressors, and storage site figures, the total well count options was used in the model. This emission factor incorporates considerations for the process as a whole. Electricity or natural gas used for processes outside of this factor may be buried in the 'Energy Consumption-Industrial' module under natural gas use and in distillate fuel, but this is combined with all industrial applications for the use of electricity or other energy sources and is undefined by the model.

11. The Oil and Gas Production SIT module bases the calculated emissions for well sites solely on number of wells and emission factors. As a result, it does not appear to take into account the differences in methane content of natural gas and oil production in different parts of the state or quantity of production from a particular well.

Response: This is correct. The model is not flexible enough to take inputs from nearly 50,000 wells and variable methane content. Average methane content figures are used by the model to reflect Colorado gas production. This is variable by year, starting with 9.07 metric tons CH4 per year per well in 1990, increasing to 10.78 $MtCO_2e$ in 2000. This decreases slightly to 10.62 mT/CO2 e in 2005 and is held constant in the model through 2030.The oil production of the model considers total statewide production in the calculation but the gas side of the model does not.

12. Many variables must be considered in reflecting emissions by well including: Conventional versus horizontal well construction, 1 mile vs. 2 mile laterals, Production, Age , Gas to Oil Ratio (GOR) and Yield.

Response: The inventory process based on well counts does not distinguish on type of well contruction, age of well, level of production or processing technologies.

13. Natural Gas Venting and Flaring

This module states that "venting and flaring of natural gas" is a common practice. In fact, the model assumes that 20% of the natural gas production facilities vent excess emission and 80% use flares to control waste gas. Moreover, the Draft Inventory fails to distinguish between oil wells with associated gas that may be flared for a period of time, due to lack of gathering infrastructure among other factors, and gas wells that typically only flare gas during well development, if at all, since gas production is the sole reason for drilling the well. The scope of those things that EPA and the Division consider venting and flaring remains unclear to CACI, and how that scope affects the numbers arrived at in the Draft Inventory. As a result, where EPA and the Division obtained these numbers is not clear, and industry respectfully disagrees with these percentages. Operators take significant efforts to reduce venting and flaring. In fact, operators are required pursuant to COGCC regulations to use green completions in certain circumstances. Furthermore, NSPS OOOO requires green completions for hydraulically fractured gas wells. In addition, many operators have ventless tanks that do not appear to be accounted for here. None of these circumstances appear to be accounted for in the module.

Response: Natural gas venting and flaring is calculated by multiplying the default Bbtu vented and flared (from the EIA Natural Gas Navigator) time 54.71 metric tons of $CO_2$ /year. The metric tons are multiplied by 80% as the percent flared. The emission factor remains constant from 1990-2010. However, the amount of NG vented and flared declines from 4,837 BBTU in 1990 to 1,273 Bbtu in 2010, even as natural gas production increased almost tenfold. The Division believes the less than 0.1 MMTCO2e/year from this practice, is given proportionally less credit in the model as rules and practices have changed from 1990-2010. While Green Completions, ventless tanks, and NSPS 0000 are not considered in the activity data provided by the EIA Natural Gas Navigator the proportionally smaller contribution from venting and flaring seem to be of little consequence in the overall natural gas picture. The final version of this inventory does not make adjustment to the venting and flaring estimates. However, the Division recognizes the most complete and accurate compilation of emissions from this sector should consider addressing venting and flaring in a

more Colorado specific manner.

## IV. Coal

1. The methane estimates assume all mines produce methane. That is not true.

Response: The Division agrees that a uniform emission rate applied to all surface and underground mines may not accurately reflect Colorado emissions. The Division is open to exploring alternative data sources and assumptions in future updates to the inventory.

2. Specific comments were made regarding the emissions from different types of mines, at different times of year leading to an overestimation of coal mine emissions

Response: The SIT Coal model relies on a variety of data sources and assumptions, most of which are industry supplied data such as the annual above and underground production quantities. The SIT Tool allows for input of basin or mine specific data as noted in the Coal User's Guide. Lacking such information the model will populate emissions by calculating methane based on fixed emissions factors and coal production data for the state. Admittedly the rate of emissions from one mining operation to the next are highly likely to be different and the model attempts to account for as many of the differences as the data allows, or reasonable assumptions can be made. The model is designed with sufficient flexibility to allow for nearly all of the input assumptions to be modified if better data is available. If the CMA has better, or different, data related to the emission from Colorado mines the Division can make such adjustments as are reasonable to change the input and outputs of the model. However, based on the use of existing industry data, and no suggested other data, and the crosschecking that was described in the Coal Emission chapter of this inventory, the Division determined that modifications would not be made in this inventory update.

3. The list of Abandoned Mines is incorrect. None of the closed Orchard Valley Mines are shown, for example, and Bowie #3 (an active operation) is listed there.

Response: The listed abandoned mines come from a national data base reportedly from industry provided information. If the list is incorrect the State can substitute with more current information. The commenter does not provide

such specifics and since the total emissions are calculated from state totals and not on a per mine basis, the Division intends to retain the data unchanged.

4. How are the "basin specific emission factors" derived?

Response: Basin specific emission factors are taken from an EPA studies of methane coal emissions from around the U.S. The Piceance basin factor of 63.8 $cfCH_4$/ton was used to calculate post-mining activity emissions multiplied by the total underground coal mined. Underground emission factors were derived from the U.S. EPA's Coalbed Methane Outreach Program; the Mine Safety and Health Administration district office records; and the 'Non-$CO_2$ Gasses and Sequestration Branch of the EPA Office of Air and Radiation. Specifics of the underground mining calculation approach are defined in the SIT Coal User's Guide. More definition as to the data and approach can be found in the EPA report, *Methane Emissions from Abandoned Coal Mines in the United States: Emission Inventory Methodology and 1990-2002 Emissions Estimates* (2004).

5. What constitutes "post mining activities" and where is the boundary between "mining activities" and "post mining activities"?

Response: The 'post mining activities', as defined by the EPA, are related to offgassing during transportation and handling of coal. Underground post-mining activities use the total coal produced and the Piceance basin emission factor of 63.8 $cfCH_4$/ton to produce 'post mining emissions'. This is added to the product of the amount of surface coal produced multiplied by 10.8 $cfCH_4$/ton (Southwest/Rockies (CO) factor).

## V. Wildfires

The draft inventory does not include emissions from wildfires and other carbon sink changes. The large wildfires in Colorado during this century, as well as scientific research indicating that a disrupted climate will likely bring more of the same in the future, make it clear that those emissions should be accounted for in the inventory.

Response:

This is something that could be considered in future updates to the inventory.

## VI. RCI Fuel Use

RCI Fuel Use should have more state specific data including publicly available sources of data through entities like the Colorado Association of Commerce & Industry (CACI)or even their own GHG Mandatory Recordkeeping and Reporting (MRR) records.

Response: The RCI energy use by fuel type drives SIT emission calculation for this segment. The basis for energy use for the the 61 sub-categories of energy use (e.g. aviation fuel, asphalt, motor gasoline, etc.) is the national annual State Energy Data System (SEDS) compiled by the EIA. The complexity of this data base and sources of information are largely based on State provided data to the EIA through various reporting system. However, as described on the SEDS web site, sources of information are in flux from one year to the next and processes change for gap filling for missing data. While CACI suggests the data base is 'purely speculative' the State believes the SEDS data base is a reasonably accurate depiction of Colorado specific data since it is compiled from a variety of state specific sources. While we agree other sources of data may exist that are more reflective of actual state energy consumption figures for specific sub-categories, the nature of such a data collection effort would be extensive and may provide little added detail to the existing process. To acquire 1990-2010 records for the 61 sub-categories of energy use would be a significant effort with uncertain outcomes as far as improved reliability of the overall inventory.